STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric O&M Expense
($000)

Case No.: U-21870
Exhibit No.: A-90 (MJF-1)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Corporate O&M

Line No.	(a) Program Description	(b) Source	(c) 2024 Actual	(d) 2025 Projected	(e) 2026 Projected	(f) 12 Months Ending 4/30/2027 Projected
1	Adjusted Corporate Services Expense	Exhibit A-91 (MJF-2)	$ 37,543	$ 38,331	$ 39,251	$ 36,968
2	Uncollectible Expense	Exhibit A-93 (MJF-4)	$ 18,074	18,998	18,998	20,274
3	Injuries & Damages Expense	Exhibit A-94 (MJF-5)	$ 7,677	5,083	5,083	5,083
4	**TOTAL O&M EXPENSES**		**$ 63,294**	**$ 62,412**	**$ 63,332**	**$ 62,325**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Projected Corporate Services O&M Expense
($000)

Case No.: U-21870
Exhibit No.: A-91 (MJF-2)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Line No.	Description	(a)	(b) 2024 Labor Actual	(c) 2024 Non-Labor Actual	(d) Total 2024 Actual	(e) 2025 Labor Inflation Projected	(f) 2025 N-Lbr Inflation Projected	(g) 12 Mos Ending 12/31/2025 Projected	(h) 2026 Labor Inflation Projected	(i) 2026 N-Lbr Inflation Projected	(j) 12 Mos Ending 12/31/2026 Projected	(k) 4 Mos Ending 4/30/27 Lbr Inflation Projected	(l) 4 Mos Ending 4/30/27 N-Lbr Inflation Projected	(m) Other Adjustment	(n) 12 Mos Ending 4/30/2027 Projected
1						(b) * Inflation	(c) * Inflation	(d) + (e) + (f)	[(b) + (e)] * Inflation	[(c) + (f)] * Inflation	(d) + (e) + (f)				(j) + (k) + (l) + (m)
2	Sustainability & External Affairs		$ 2,764	$ 2,243	$ 5,007	$ 58	$ 47	$ 5,112	$ 68	$ 55	$ 5,235	$ 23	$ 19	$ -	$ 5,277
3	Legal, Ethics, Regulatory, and Risk		7,136	19,207	26,343	150	403	26,896	175	471	27,542	60	161	(2,597)	25,165
4	People & Culture and Learning and Development		8,205	1,742	9,946	172	37	10,155	201	43	10,399	69	15	-	10,482
5	Finance and Shared Services		11,960	5,285	17,246	251	111	17,608	293	130	18,030	100	44	-	18,174
6	General Activities		(2,654)	(3,011)	(5,665)	(56)	(63)	(5,784)	(65)	(74)	(5,923)	(22)	(25)	-	(5,970)
7	Total		$ 27,410	$ 25,467	$ 52,877	$ 576	$ 535	$ 53,987	$ 672	$ 624	$ 55,283	$ 229	$ 213	$ (2,597)	$ 53,129
8	Less: EICP		14,442	-	14,442	303	-	14,745	354	-	15,099	121	-	-	$ 15,220
9	Less: Transfers Out		-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Corporate Service Departments		$ 12,968	$ 25,467	$ 38,435	$ 272	$ 535	$ 39,242	$ 318	$ 624	$ 40,184	$ 108	$ 213	$ (2,597)	$ 37,909
11	Administration & Other-Electric Portion		-	2,919	2,919	-	61	2,980	-	72	3,052	-	24	-	$ 3,076
12	**Total Corporate Services**		$ 12,968	$ 28,386	$ 41,354	$ 272	$ 596	$ 42,223	$ 318	$ 696	$ 43,236	$ 108	$ 237	$ (2,597)	$ 40,985
	Normalizations														
13	One-time Consultant Expense		-	(3,812)	(3,812)	-	(80)	(3,892)	-	(93)	(3,985)	-	(32)	-	$ (4,017)
14	**Total Normalizations**		$ -	$ (3,812)	$ (3,812)	$ -	$ (80)	$ (3,892)	$ -	$ (93)	$ (3,985)	$ -	$ (32)	$ -	$ (4,017)
15	**TOTAL ADJUSTED CORPORATE SERVICES EXPENSE**		$ 12,968	$ 24,575	**$ 37,543**	$ 272	$ 516	**$ 38,331**	$ 318	$ 602	**$ 39,251**	$ 108	$ 206	**$ (2,597)**	**$ 36,968**

		2025	2026	2027
16	Annual inflation rates per WP-PDD-37			
	Annual inflation rates	2.1%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.1%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
S&P Global Market Intelligence Ranking of Consumers Energy Electric A&G Costs for 2023
Ranked by A&G per Customer (less Pension and Benefits)
(Companies over 500K Customers)

Case No.: U-21870
Exhibit No.: A-92 (MJF-3)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Company Name	Total Customers (actual)	Total Admin & Gen: O&M Expense ($000)	Total Admin & Gen: Pension & Benefits ($000)	Total Admin & Gen: Excluding Pension & Benefits (d) - (e) ($000)	Total Admin & Gen: Excluding Pension & Benefits $/Customer (f)/(c) x $1,000	$/Customer Ranking
1	Ohio Power Company	1,523,794	64,072	-9,266	73,338	$48.13	1
2	Duke Energy Ohio, Inc.	752,909	49,306	7,263	42,043	$55.84	2
3	**Consumers Energy Company**	**1,884,290**	**67,227**	**-40,113**	**107,340**	**$56.97**	**3**
4	Wisconsin Electric Power Company	1,159,300	97,531	29,079	68,452	$59.05	4
5	MidAmerican Energy Company	820,668	75,919	25,104	50,815	$61.92	5
6	Public Service Electric and Gas Company	2,369,557	125,552	-27,412	152,964	$64.55	6
7	Public Service Enterprise Group Incorporated	2,369,557	125,552	-27,412	152,964	$64.55	7
8	Evergy Metro, Inc.	579,977	37,777	-468	38,245	$65.94	8
9	WEC Energy Group, Inc.	1,659,673	155,809	45,757	110,052	$66.31	9
10	Ohio Edison Company	1,069,766	46,565	-24,401	70,966	$66.34	10
11	CenterPoint Energy Houston Electric, LLC	2,753,976	242,169	52,924	189,245	$68.72	11
12	DTE Electric Company	2,266,460	238,578	75,564	163,014	$71.92	12
13	The Cleveland Electric Illuminating Company	756,673	78,801	23,176	55,625	$73.51	13
14	Public Service Company of Oklahoma	575,846	38,627	-3,980	42,607	$73.99	14
15	Metropolitan Edison Company	588,329	68,232	23,351	44,881	$76.29	15
16	Pennsylvania Electric Company	588,213	46,084	-112	46,196	$78.54	16
17	CenterPoint Energy, Inc.	2,909,158	290,357	61,423	228,934	$78.69	17
18	Virginia Electric and Power Company	2,752,726	264,764	42,175	222,589	$80.86	18
19	Appalachian Power Company	965,517	70,918	-10,421	81,339	$84.24	19
20	Public Service Company of Colorado	1,569,461	183,902	48,313	135,589	$86.39	20
21	West Penn Power Company	737,355	64,841	830	64,011	$86.81	21
22	Nevada Power Company	1,015,168	108,561	19,611	88,950	$87.62	22
23	Commonwealth Edison Company	4,130,538	441,205	74,977	366,228	$88.66	23
24	Florida Power & Light Company	5,845,147	547,158	25,433	521,725	$89.26	24
25	NextEra Energy, Inc.	5,845,147	562,017	25,419	536,598	$91.80	25
26	Dominion Energy, Inc.	3,542,947	410,578	83,932	326,646	$92.20	26
27	PECO Energy Company	1,700,223	184,377	17,303	167,074	$98.27	27
28	Central Maine Power Company	666,319	64,647	-1,915	66,562	$99.90	28
29	American Electric Power Company, Inc.	4,481,146	440,048	-37,624	477,672	$106.60	29
30	PPL Electric Utilities Corporation	1,472,437	158,321	1,288	157,033	$106.65	30
31	Avangrid, Inc.	2,321,099	243,877	-7,713	251,590	$108.39	31
32	Duke Energy Carolinas, LLC	2,845,809	351,358	38,022	313,336	$110.10	32
33	Exelon Corporation	9,225,536	1,215,815	176,078	1,039,737	$112.70	33
34	Ameren Illinois Company	1,226,027	88,022	-53,965	141,987	$115.81	34
35	OGE Energy Corp.	892,274	171,377	67,690	103,687	$116.21	35
36	Oklahoma Gas and Electric Company	892,274	171,377	67,690	103,687	$116.21	36
37	Puget Energy, Inc.	1,224,326	172,081	28,392	143,689	$117.36	37
38	Puget Sound Energy, Inc.	1,224,326	172,081	28,392	143,689	$117.36	38
39	Southwestern Electric Power Company	552,060	66,662	1,774	64,888	$117.54	39
40	Duke Energy Indiana, LLC	894,160	119,298	11,436	107,862	$120.63	40
41	New York State Electric & Gas Corporation	919,140	102,083	-10,577	112,660	$122.57	41
42	PPL Corporation	2,476,169	342,020	35,919	306,101	$123.62	42
43	Consolidated Edison Company of New York, Inc.	3,645,153	277,985	-174,234	452,219	$124.06	43
44	The Dayton Power and Light Company	539,127	80,410	12,497	67,913	$125.97	44
45	Evergy, Inc.	1,662,492	239,786	29,980	209,806	$126.20	45
46	Dominion Energy South Carolina, Inc.	790,221	140,183	39,911	100,272	$126.89	46
47	Baltimore Gas and Electric Company	1,336,794	209,771	38,291	171,480	$128.28	47
48	Consolidated Edison, Inc.	3,962,971	343,637	-167,210	510,847	$128.91	48
49	Xcel Energy Inc.	3,801,019	691,569	200,358	491,211	$129.23	49
50	Arizona Public Service Company	1,370,930	216,807	38,008	178,799	$130.42	50
51	Pinnacle West Capital Corporation	1,370,930	216,807	38,008	178,799	$130.42	51
52	Jersey Central Power & Light Company	1,163,141	175,048	23,186	151,862	$130.56	52
53	Georgia Power Company	2,735,261	315,548	-50,484	366,032	$133.82	53
54	Ameren Corporation	2,480,189	283,448	-61,214	344,662	$138.97	54
55	Northern States Power Company	1,556,301	329,363	108,296	221,067	$142.05	55
56	Oncor Electric Delivery Company LLC	3,936,106	680,454	117,846	562,608	$142.94	56
57	Alliant Energy Corporation	995,135	184,872	40,912	143,960	$144.66	57
58	Indiana Michigan Power Company	610,647	89,156	-337	89,493	$146.55	58
59	Duke Energy Progress, LLC	1,718,128	314,441	61,689	252,752	$147.11	59
60	NSTAR Electric Company	1,477,991	175,836	-43,912	219,748	$148.68	60
61	Atlantic City Electric Company	569,973	95,418	9,659	85,759	$150.46	61
62	Interstate Power and Light Company	500,038	98,241	22,527	75,714	$151.42	62
63	Union Electric Company	1,254,162	188,547	-7,254	195,801	$156.12	63
64	Kentucky Utilities Company	569,612	108,921	19,307	89,614	$157.32	64
65	Duke Energy Corporation	8,330,346	1,435,299	123,668	1,311,631	$157.45	65
66	Eversource Energy	3,296,846	485,985	-42,609	528,594	$160.33	66
67	Entergy Texas, Inc.	506,334	109,762	27,826	81,936	$161.82	67
68	Public Service Company of New Hampshire	537,201	89,877	704	89,173	$166.00	68
69	Delmarva Power & Light Company	549,745	102,526	11,024	91,502	$166.44	69
70	Potomac Electric Power Company	938,263	182,517	24,826	157,691	$168.07	70
71	Evergy Kansas Central, Inc.	738,636	154,088	28,976	125,112	$169.38	71
72	The Connecticut Light and Power Company	1,281,654	220,273	599	219,674	$171.40	72
73	The Southern Company	4,463,993	678,551	-101,941	780,492	$174.84	73
74	IDACORP, Inc.	625,440	174,739	61,209	113,530	$181.52	74
75	Idaho Power Company	625,440	174,739	61,209	113,530	$181.52	75
76	The AES Corporation	1,062,522	238,299	45,411	192,888	$181.54	76
77	Portland General Electric Company	928,859	222,693	49,091	173,602	$186.90	77
78	Duquesne Light Company	611,282	128,098	12,921	115,177	$188.42	78
79	Duquesne Light Holdings, Inc.	611,282	128,098	12,921	115,177	$188.42	79
80	Entergy Arkansas, LLC	729,557	212,309	67,048	145,261	$199.11	80
81	Entergy Louisiana, LLC	1,104,472	340,835	113,862	226,973	$205.50	81
82	Niagara Mohawk Power Corporation	1,542,713	359,022	40,457	318,565	$206.50	82
83	Alabama Power Company	1,537,035	274,702	-55,290	329,992	$214.69	83
84	Entergy Corporation	3,009,516	923,653	272,927	650,726	$216.22	84
85	UNS Energy Corporation	550,256	148,148	28,426	119,722	$217.58	85
86	AES Indiana	523,395	157,889	32,914	124,975	$238.78	86
87	TXNM Energy, Inc.	820,083	227,572	26,936	200,636	$244.65	87
88	Tampa Electric Company	834,144	255,708	36,062	219,646	$263.32	88
89	TECO Energy, Inc.	834,144	255,708	36,062	219,646	$263.32	89
90	Public Service Company of New Mexico	548,019	177,866	20,655	157,211	$286.87	90
91	Duke Energy Florida, LLC	1,968,213	576,847	1,149	575,698	$292.50	91
92	National Grid USA	2,583,968	926,117	110,732	815,385	$315.56	92
93	Edison International	5,263,405	2,149,362	57,140	2,092,222	$397.50	93
94	Southern California Edison Company	5,263,405	2,149,362	57,140	2,092,222	$397.50	94
95	Massachusetts Electric Company	635,003	319,669	43,085	276,584	$435.56	95
96	Berkshire Hathaway Energy Company	4,280,660	2,198,281	180,335	2,017,946	$471.41	96
97	Pacific Gas and Electric Company	5,649,612	3,534,378	383,249	3,151,129	$557.76	97
98	PG&E Corporation	5,649,612	3,534,378	383,249	3,151,129	$557.76	98
99	PacifiCorp	2,069,044	1,953,618	123,037	1,830,581	$884.75	99
100	San Diego Gas & Electric Company	512,632	626,994	63,809	563,185	$1,098.61	100

S&P Global Market Intelligence, 55 Water Street, New York, NY 10041
Columns c-e from S&P Global for regulated electric companies with more than 500,000 customers.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense
($000)

Case No.: U-21870
Exhibit No.: A-93 (MJF-4)
Page: 1 of 2
Witness: MJFoster
Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 2025 Projected	(d) 2026 Projected	(e) 12 Months Ending 4/30/2027 Projected
1	Uncollectible Accounts Expense	$ 18,074	$ 18,998 [1]	$ 18,998 [2]	**$ 20,274** [3]

[1] 2025 projected amount based on U-21585 order
[2] 2026 projected amount based on U-21585 order
[3] Exhibit A-93 (MJF-4) Page 2, line 9, column (e)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense
for 12 Mos. Ending 4/30/2027
($000)

Case No.: U-21870
Exhibit No.: A-93 (MJF-4)
Page: 2 of 2
Witness: MJFoster
Date: June 2025

Line No.	(a) Year	(b) Gross Charge-Offs	(c) Less Recoveries	(d) Net Write-Offs	(e) Total Electric Service Revenue MPSC P-521 P. 304.1 col (c) + P. 305 col (c)	(f) BDLR col (d) / col (e)
1	2020	22,393	11,965	10,428	4,147,450	0.251%
2	2021	26,335	10,844	15,491	4,681,931	0.331%
3	2022	27,543	8,726	18,817	4,737,236	0.397%
4	2023	29,146	7,478	21,668	4,709,798	0.460%
5	2024	25,816	7,742	18,074	4,934,300	0.366%
6	3-Year Average 2022 - 2024	$ 27,501	$ 7,982	$ 19,519	$ 4,793,778	0.407%
7	Test Year Total Company Electric Revenues and Deliveries Exhibit A-15 (EMB-3), Schedule E-2, Page 1 of 1 Row 24, Column (j) - Row 24, Column (c)				$ 4,979,036	
8	3-Year Average 2022 - 2024				0.407%	
9	Test Year Total Uncollectible Accounts Expense				**$ 20,274**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Injuries & Damages Expense
for the Years 2020 Through the 12 Months Ending 4/30/2027
($000)

Case No.: U-21870
Exhibit No.: A-94 (MJF-5)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Line No.	(a) Program Description		(b) 2020 Actual	(c) 2021 Actual	(d) 2022 Actual	(e) 2023 Actual	(f) 2024 Actual	(g) 12 Mos Ending 12/31/2025 Projected	(h) 12 Mos Ending 12/31/2026 Projected	(i) 12 Mos Ending 4/30/2027 Projected
1	Electric Injuries & Damages	[1]	$ 2,021	$ 2,694	$ 5,567	$ 4,311	$ 6,619	$ 4,242	$ 4,242	$ 4,242
2	Internal Legal Costs	[2]	452	412	424	474	441	441	441	441
3	Workers' Compensation	[3]	(139)	401	661	462	617	400	400	400
4	Total Electric Injuries & Damages		**$ 2,334**	**$ 3,507**	**$ 6,652**	**$ 5,246**	**$ 7,677**	**$ 5,083**	**$ 5,083**	**$ 5,083**

[1] Electric Injuries & Damages costs are 2020 - 2024 actual expense. 2025, 2026, and Test Year Ending 4/30/2027 used a 5-year average (2020 - 2024).

[2] Electric Internal Legal costs are 2020 - 2024 actual expense. 2025, 2026, and Test Year Ending 4/30/2027 used a 5-year average (2020 - 2024).

[3] Electric Workers' Compensation costs are 2020 - 2024 actual expense. 2025, 2026, and Test Year Ending 4/30/2027 used a 5-year average (2020 - 2024).

Schedule: B-5.4

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

Case No.: U-21870
Exhibit No.: A-12 (MJF-6)
Schedule: B-5.4
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ending 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Corporate Capital	1,010	1,031	347	1,378	1,064
	Contractor	587	599	201	800	619
	Labor	73	75	25	100	77
	Materials	223	228	77	305	235
	Business Expenses	127	130	44	174	134
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
2	**Total Capital**	1,010	1,031	347	1,378	1,064

		Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
3	Corporate Capital	344	1,034	1,064	2,443
	Contractor	200	601	619	1,420
	Labor	25	75	77	177
	Materials	76	228	235	539
	Business Expenses	43	130	134	307
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
4	**Total Capital**	344	1,034	1,064	2,443

		2025	2026	2027
5	Annual inflation rates per WP-PDD-37			
	Annual inflation rates	2.1%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.1%	2.4%	0.8%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Demand Response C&I and Residential Programs
($000)

Case No.: U-21870
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.5
Page: 1 of 1
Witness: AMGast
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Demand Response (C&I)	287	1,350	60	1,410	180
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	287	1,350	60	1,410	180
	Contractor	-	-	-	-	-
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
2	Demand Response (Res)	4,868	656	208	864	1,375
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	4,868	656	208	864	1,375
	Contractor	-	-	-	-	-
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
3	Total Demand Response Capital	5,156	2,006	268	2,274	1,555
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	5,156	2,006	268	2,274	1,555
	Contractor	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Demand Response C&I and Residential Programs
($000)

Case No.: U-21870
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.5
Page: 2 of 2
Witness: AMGast
Date: June 2025

	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
4	Demand Response (C&I)	450	960	180	1,590
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	450	960	180	1,590
	Contractor	-	-	-	-
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
5	Demand Response (Res)	202	662	1,375	2,239
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	202	662	1,375	2,239
	Contractor	-	-	-	-
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
6	Total Demand Response Capital	652	1,622	1,555	3,829
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	652	1,622	1,555	3,829
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
For Demand Response C&I and Residential Programs
($000)

Case No.: U-21870
Exhibit No.: A-95 (AMG-2)
Page: 1 of 2
Witness: AMGast
Date: June 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	Demand Response (C&I)	16,694	20,983
	Labor	4,106	3,998
	Material	13	16
	Contractor	5,827	8,745
	Non-Labor Overhead	-	-
	Non-Labor Other	6,748	8,224
2	Demand Response (Res)	14,546	13,648
	Labor	3,016	2,763
	Material	163	119
	Contractor	7,670	8,074
	Non-Labor Overhead	-	-
	Non-Labor Other	3,697	2,692
3	Total Demand Response O&M Expenses	31,240	34,630
	Labor	7,122	6,761
	Material	176	135
	Contractor	13,497	16,819
	Non-Labor Overhead	-	-
	Non-Labor Other	10,444	10,916

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Add Description
($000)

Case No.: U-21870
Exhibit No.: A-95 (AMG-2)
Page: 2 of 2
Witness: AMGast
Date: June 2025

Line No.	Description	(a)	(b) 12-Mos Ended 12 Mos Ended 12/31/2024	(c) Base O&M for Merit & Inflation 12 Mos Ended 12/31/2024	(d) Merit & Inflation 12 Mos Ending 12/31/2025	(e) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2025	(f) Merit & Inflation 12 Mos Ending 12/31/2026	(g) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2026	(h) Merit & Inflation 4 Mos Ending 4/30/2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending 4/30/2027
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Demand Response (C&I)		16,694	16,694	351	17,044	409	17,453	140	3,390	20,983
	Labor		4,106	4,106	86	4,192	101	4,293	34	(329)	3,998
	Material		13	13	0	13	0	13	0	2	16
	Contractor		5,827	5,827	122	5,949	143	6,092	49	2,605	8,745
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		6,748	6,748	142	6,889	165	7,055	56	1,113	8,224
2	Demand Response (Res)		14,546	14,546	305	14,852	356	15,208	122	(1,682)	13,648
	Labor		3,016	3,016	63	3,079	74	3,153	25	(416)	2,763
	Material		163	163	3	167	4	171	1	(53)	119
	Contractor		7,670	7,670	161	7,831	188	8,019	64	(10)	8,074
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		3,697	3,697	78	3,774	91	3,865	31	(1,204)	2,692
3	Total Demand Response O&M Expenses		31,240	31,240	656	31,896	765	32,661	261	1,708	34,630
	Labor		7,122	7,122	150	7,272	175	7,446	60	(745)	6,761
	Material		176	176	4	180	4	184	1	(51)	135
	Contractor		13,497	13,497	283	13,781	331	14,112	113	2,595	16,819
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		10,444	10,444	219	10,663	256	10,919	87	(91)	10,916

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

Whole Home Optimization Demand Response Pilot

1. Pilot needs and goals detailed.

a. Need for the pilot and results of past pilots

The utility industry is rapidly adopting new technologies to engage customers in low-effort and minimally disruptive DR programming and the Company is seeking to collect field data on the potential for adoption of, and load shaping capabilities of, these technologies in Michigan. Major technology companies have developed the hardware and software necessary to administer these programs and are actively seeking utilities with whom to partner on feasibility testing and implementation.

To address these needs and opportunities, the Company is proposing a Whole Home Optimization Demand Response pilot that will test customer-owned smart home energy management systems, battery storage, and load management devices. A whole home optimization approach allows us to test how customers respond to and interact with energy usage and demand analytics, customer-controlled responses and behavior, and aggregation of resources within their home. The key technologies evaluated in this pilot are as follows:

Smart Home Energy Management System (SHEMS) – SHEMS platforms and software are advanced systems designed to monitor, analyze, and optimize energy consumption through a single device or application. These tools leverage data from various sources, including smart devices like thermostats, sensors, appliances, and intelligent assistants to provide actionable insights and control over energy usage.

Customers will benefit from real-time accurate energy data, which in addition to savings, can provide energy education and actionable insights, more readily available in-home automation, and energy optimization.

Battery Storage – Battery storage in the context of this pilot refers to a rechargeable home battery system that stores electrical energy for later use and could include electric vehicles if a feasible solution is determined. These systems typically consist of rechargeable batteries, an inverter, and a control system. The Company will seek out systems that come with advanced monitoring tools that allow customers to track energy consumption and storage in real time and can integrate with other distributed energy resources, smart home devices, and energy management systems – giving them control and autonomy in shifting energy use throughout the day. This allows for automated control of energy usage, such as charging the battery during off-peak hours and using stored energy during peak times.

Load Management Devices – Devices in this category can range from smart control panels to meter collars and are used to monitor and control the flow of electricity to ensure the electrical panel or grid doesn't become overloaded. Load Management Devices are often integrated with Smart Home Energy Management Systems to aid with load shaping according to homeowner preference, to control energy consumption, and to potentially eliminate utility service upgrades while enabling enhanced grid-edge capabilities. They provide a unique aggregated DR opportunity with the integration of electric vehicles and battery storage systems by acting as a whole

home DR platform using virtual service limit capabilities, with up to 10 times that of a single-point DR solution. Load Management Devices can also create a more cost-effective and faster electrification method of EV adoption, and it 'future-proofs' customer's homes for further electrification needs. These devices can benefit customers by helping them reduce energy use when it is most expensive, lowering their overall energy bill, and helping them participate in clean energy plans that still provide them with control over the decision to use energy when it is cleanest and use less energy when it is less ideal for the environment.

Past Pilots: Launched in 2020 as part of a settlement agreement, the Super-Efficient, All-Electric New Homes pilot aimed to decarbonize residential buildings and assess the potential of zero energy-ready homes in Michigan. This pilot incentivizes home-building partners to develop scalable production of affordable, high-performance single-family homes, evaluating energy bill impacts, heat pump performance, customer comfort, builder barriers, and cost-effectiveness. To date the pilot has 57 homes enrolled, each with a mix of energy efficient decarbonization and electrification measures. These measures include cold climate air-source heat pumps ("ccASHP") with energy recovery ventilators ("ERV"), heat pump water heaters ("HPWH"), comprehensive air sealing, premium insulations, high-efficiency windows, and ENERGY STAR appliances. A select number of projects were also eligible to receive rooftop solar arrays to understand conditions for achieving near-net zero energy and mitigate potentially higher utility costs associated with living in an all-electric home.

Additionally, six of the homes had submetering equipment installed to collect circuit level consumption data.

From this pilot, the Company learned that there are opportunities to test for DR through aggregation of resources with solar and battery storage, with use-cases identified for battery dispatching partnered with solar for testing resource aggregation. Customers also provided feedback on how demand response offerings could help them reach zero net energy and reduce energy costs. By deploying sub-metering equipment to collect circuit level data the Company learned that the average per home summer peak was 1.32 kW and average per home winter peak winter was 2.48 kW. This pilot indicated that DR offerings could impact whole home usage and that aggregated resources could work together to promote net zero energy.

b. Pilot goals and desired learnings

The Company is seeking to test this technology specifically with its residential customers given the past implementation of Time-of-Use ("TOU") rate structures (RSP_1001, RSH 1040, and RPM 1050), to quantify energy savings impacts, and to understand the barriers customers face with adopting distributed energy resources ("DER") in the home, including battery storage and electric vehicles, to shift energy off-peak. As more smart-ready devices become available, the Company must understand how customers interact with their energy usage via these devices. Currently, the Company does not have any active efforts to explore residential DR potential beyond current programming, limiting the impact the Company can have on residential peak demand and potentially jeopardizing

future DR cost-effectiveness. Additionally, incorporating EVs and other DERs into the DR portfolio has not been tested due to a limited understanding of how to best incentivize customers for participation in such programs and if there is a source of significant benefit to load management energy savings and grid benefits. The goal of the pilot would be to identify and quantify benefits from the perspective of load reduction and customer willingness-to-pay.

Research also shows that customers prioritize comfort and safety while also wanting to lower their energy bills and usage and we expect that this pilot will expand these learnings via recruitment of a larger sample and deeper exploration of customer attitudes and behaviors.

2. Design and evaluation plan

a. Pilot program design and evaluation plans

The Company will work with implementation contractors, third-party evaluators, and software and hardware vendors to install and test a variety of available technologies to assess cost-effectiveness, demand reduction, energy waste reduction, customer interest, and technical integration feasibility. Objective criteria for evaluating the success of the pilot include measuring the reduction in kilowatts per participant, assessing the cost-effectiveness of the pilot, and evaluating customer experience of and satisfaction with the

pilot technologies and programs through Customer Satisfaction ("CSAT") scores and the Customer Experience Index ("CXI").

b. Define target customer population, selection rationale (including those for location-driven programs), recruitment plans, and evaluation plans for customer adoption and satisfaction.

The Company will deploy a marketing and recruiting plan that supports enrolling approximately 500 residential electric or combination service territory customers that are single-family market rate, single-family low- to moderate-income, and multi-family units. Each residence will receive one or more of the tools for testing, depending on household needs and configuration. The Company will measure conversion and enrollment rates and will partner with a third-party evaluator to measure customer satisfaction and identify opportunities for improvement.

c. If statistical analysis will be conducted on pilot results, a statistically significant sample size must be selected, supported, and detailed. If a statistically significant sample size is not selected, justification must be provided.

The Company will engage with a third-party evaluator to validate if a statistically significant sample size is required and will build the recruitment plan to acquire the number of enrollments needed. The company will work with the third-party evaluator to build a comprehensive evaluation plan that includes pilot design and size, key testing assumptions, methodology for measuring impact on energy usage and peak demand reduction, and customer satisfaction.

d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.

See above.

e. If changes are required during implementation, pilot design, and evaluation impacts are shared.

The Company will provide updates on this pilot in its future electric rate cases and DR reconciliations and will notify MPSC Staff and other intervenors of significant changes from the approved plan during implementation or pilot design and will share the results of evaluation when complete, in accordance with the stakeholder engagement process outline below.

3. Pilot project costs detailed

a. Project costs detailed by source and amount for applicable periods

The project costs will be tracked internally and will include implementation costs, vendor costs, and administrative costs. The Company is seeking $750,000 capital and $250,000 O&M included in Exhibit A-XX (AMG-1) and Exhibit A-XX (AMG-2), respectively. The costs associated with testing these technologies include technology demonstrations for the various customer types. Load Management Devices will require an investment of $200,000, multifamily whole unit optimization will require $200,000, single-family whole home optimization will require $150,000, and smart analytics and aggregation through whole home smart optimization will require $200,000. Additionally, evaluation, incubation, and labor costs are estimated at $250,000.

b. Availability/pursuit of non-utility funding

The Company is not aware of outside funding available for this type of project but will seek learnings on how customers can stack incentives for technologies such as solar panels, batteries, EVs, etc. to decrease their overall out-of-pocket investment.

c. Anticipated cost-effectiveness and net benefits when deployed at scale

To be determined when evaluation work is completed. Leading indicators and confirmed findings will be shared during quarterly updates.

d. Proposed rate recovery approach

The funding requested for this project is identified in item (a) above and included in the revenue requirement for this case.

4. Project timeline

a. Proposed timeline for the pilot project and any related reports or evaluations

Phase 1 (May – August 2026) involves evaluating current assets to determine potential inclusion and securing third-party partner agreements. In Phase 2 (September 2026 – December 2026), we will geotarget customer populations and perform feasibility studies to properly test the consumer market for each use case. Phase 3 (January 2027 – April 2027) will involve scoping and launching each technology use case based on immediate feasibility. Finally, in Phase 4 (April 2027 – December 2028), we will finalize the evaluation and share a summary with stakeholders for scaling, sunsetting, or continual pilot recommendations.

5. Stakeholder engagement plan

a. Stakeholder engagement plan before, during, and after pilot takes place

Engaging stakeholders throughout the pilot is crucial for its success. We will work with interveners and interested parties in Phase 1 to finalize the scope and list of technologies to be tested.

b. Interim and final stakeholder reporting

Quarterly progress meetings will be held throughout the pilot to share updates with Commission Staff, and an annual in-depth review will be provided to third-party collaborators to gather more detailed feedback. Once the pilot concludes, final review meetings will be held to discuss outcomes and next steps.

c. Expected publicly available data from pilot shared under proper protections and privacy

Not applicable at this time.

6. Public interest

a. Public interest justification, including supporting the transition to clean, distributed energy resources; enhancing reliability, safety, affordability, or equity; or other related goals, and the pilot's expected impacts.

Based on customer research performed by the Company, it was determined that a significant population of customers believe they can make an impact on the environment by changing their behaviors and take into consideration the environmental impact of products/services they purchase. The work being done in this pilot looks to empower our

customers to become more aware of and readily reduce their energy use without significant impacts to comfort or convenience.

b. Any added benefits to ratepayers or the energy delivery system, either due to proposed site selection or through other pilot variables, especially if any system weaknesses or forecasted needs are addressed.

Demand response impacts energy delivery by encouraging customers to reduce or shift their electricity usage during peak demand periods, which improves grid stability, reduces the need for peaking power plants, and can lead to cost savings for customers. The technologies proposed for this pilot are designed to allow for increased customer involvement in DR via fuller and more nuanced customer control of energy usage.

c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills

By moderating energy usage during peak demand, DR programs like these can prevent grid overload, avoid usage of expensive power plants, and reduce the need to build new generation assets, leading to lower overall utility costs and customers' energy bills, as well as higher customer satisfaction.

d. Expected local or Michigan-based employment and business opportunities created by pilot

The pilot will require partners in implementation, manufacturers, and contractors and the Company will assess all opportunities available to use talent in Michigan and help support local economies. This will be assessed in line with cost, capabilities offered, delivery times, and expertise and maturity in the selected area.

e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations

Low- to moderate-income customers will be included in the pilot, allowing the Company to better understand the unique adoption barriers these customers face when considering implementing these technologies and identify new ways for them to participate in demand response. The Company will better understand the incentive structures that are most attractive and accessible to LMI customers, supporting the successful scaling of these technologies if appropriate.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

BRITTANI A. GRAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

1. Tariff Sheet Nos. A-4.00, A-5.00, C-50.00, C-51.00 and D-80.00 – Rule C10.4 – **Experimental Advanced Renewable Program – Anaerobic Digestion Program** – Canceled Tariff Sheets to remove rule C10.4 and to remove from Rate Schedules.

2. Tariff Sheet No. C-4.00 – Rule C1 – **Characteristics of Service** – Updated Contribution in Aid of Construction Allowance Sheet.

3. Tariff Sheet No. C-15.00 – Rule C4.4 – **Resale** – Revised all inclusive rate per kWh for resale.

4. Tariff Sheet No. C-18.00 – Rule C4.5 – **Mobile Home Park** – Updated New Service Connection fee for underground service.

5. Tariff Sheet Nos. C-23.00 and C-24.00 – **Shutoff Protection Plan for Residential Customers** – Expanded income eligibility for the Shutoff Protection Plan by raising the income eligibility limit.

6. Tariff Sheet No. C-25.00 – Rule C5.5 – **Non-Transmitting Meter Provision** – Revised monthly and upfront charges when electing a non-transmitting meter.

7. Tariff Sheet Nos. C-26.20 through C-28.00 – Rule C6.1 – **Overhead Extension Policy** – Added New Service Connection fee for overhead service and reformatted Tariff Sheet.

8. Tariff Sheet Nos. C-31.00 and C-32.00 – Rule C6.2 – **Underground Policy** – Updated New Service Connection fee for underground service.

9. Tariff Sheet No. C-36.00 – Rule C8 – **Power Supply Cost Recovery** – Updated the PSCR adjustment factor.

10. Tariff Sheet Nos. C-64.30 through C-64.50 – Rule C11.3 – **Distributed Generation Program** – Updated tariffs to reflect revised outflow credits.

11. Tariff Sheet Nos. C-77.00, D-66.00, D-78.20, D-82.00, E-22.00, E-24.00 and E-26.00 – **Line Loss Factors** – Updated line loss factors.

12. Tariff Sheet No. C-78.00 – Rule C18 – **Standard Offer - Purchased Power** – Revised Standard Offer PPA to require a minimum contract term of one year.

13. Tariff Sheet Nos. D-2.20, D-2.40, and D-5.00 – **Surcharges** – Updated to add the Investment Recovery Mechanism Surcharge, the Electric Rate Case Deferral Surcharge, and the Electric Rate Case Demand Response Surcharge.

14. Tariff Sheet Nos. D-14.00, D-15.00, D-17.00, D-36.00, D-36.10, D-38.00, D-40.00, D-40.50, D-42.00, D-43.00, D-44.10, D-44.20, D-45.00, D-46.00, D-48.00 through D-50.00, D-51.00, D-53.00, D-55.00 through D-57.00, D-59.00 through D-63.00, D-66.00, D-67.10 through D-67.30, D-71.00, D-72.00, D-75.00 through D-77.00, D-78.20, D-78.30, D-82.00 through D-83.10, D-85.00, D-86.00, D-90.10, D-90.20, D-94.00, D-94.20, D-94.30 and D-96.00 – **Rate Schedules** – Revised prices.

15. Tariff Sheet No. D-48.00 – **General Service Time of Use Rate GSTU** – Clarified eligibility for participation in Demand Response Programs under Rate GSTU.

16. Tariff Sheet No. D-63.00 – **Aggregate Peak Demand Service Provision (GAP)** – Modified eligibility to permit Company-approved enrollment exceptions.

17. Tariff Sheet Nos. D-78.30 and D-78.40 – **Large Economic Development Rate LED** – Added Adjustment for Power Factor, included a facilities allowance for funding incremental distribution facilities needed to serve a customer's load and reformatted Tariff Sheet.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Proposed Electric Tariff Sheets (MPSC No. 14 - Redlined Version)

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Proposed Electric Tariff Sheets (MPSC No. 14 - Redlined Version)

For all pricing changes on the following tariff sheets, refer to Exhibit A-16 (LMC-3) Schedule F-3.0, pages 1-23

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. A-4.00**

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(Continued From Sheet No. A-3.00)

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C9.	SECURITIZATION CHAR.GES	
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C10.5	Pilot Solar Gardens Program	C-52.00
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SECTION D
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(Continued on Sheet No. A-5.00)

See Gray Testimony, Page 5, Lines 10-15; Exhibit A-96 (Gray-1), Item No. 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. A-5.00**

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(Continued From Sheet No. A-4.00)

SECTION D
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GENERAL SERVICE SECONDARY DEMAND RATE GSD	D-51.00
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LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD	D-59.00
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See Gray Testimony, Page 5, Lines 10-15; Exhibit A-96 (Gray-1), Item No. 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-4.00**

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (Contd)

Contribution In Aid of Construction Allowance Schedule							
Schedule	Customer Voltage Level (CVL)	With a Full Service Contract, by Contract Duration					Without Full Service Contract
		1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	*$0.011/kWh* ~~$0.008/kWh~~	*$0.021/kWh* ~~$0.016/kWh~~	*$0.030/kWh* ~~$0.023/kWh~~	*$0.039/kWh* ~~$0.030/kWh~~	*$0.047/kWh* ~~$0.036/kWh~~	*$0.011/kWh* ~~$0.008/kWh~~
	2	$0.014/kWh	$0.027/kWh	$0.039/kWh	$0.050/kWh	$0.060/kWh	$0.014/kWh
	3	$0.024/kWh	*$0.046/kWh* ~~$0.045/kWh~~	$0.066/kWh	*$0.086/kWh* ~~$0.085/kWh~~	*$0.103/kWh* ~~$0.102/kWh~~	$0.024/kWh
Large General Service Primary Demand Rate GPD	1	*$30/kW* ~~$25/kW~~	*$60/kW* ~~$45/kW~~	*$90/kW* ~~$70/kW~~	*$115/kW* ~~$90/kW~~	*$135/kW* ~~$105/kW~~	*$30/kW* ~~$25/kW~~
	2	*$45/kW* ~~$50/kW~~	*$90/kW* ~~$95/kW~~	*$130/kW* ~~$135/kW~~	*$170/kW* ~~$175/kW~~	*$205/kW* ~~$215/kW~~	*$45/kW* ~~$50/kW~~
	3	$75/kW	*$140/kW* ~~$150/kW~~	*$205kW* ~~$215/kW~~	*$260/kW* ~~$280/kW~~	*$315/kW* ~~$335/kW~~	$75/kW
General Service Primary Time-of-Use Rate GPTU	1	$0.008/kWh	*$0.016/kWh* ~~$0.015/kWh~~	*$0.023/kWh* ~~$0.022/kWh~~	*$0.029/kWh* ~~$0.028/kWh~~	*$0.035kWh* ~~$0.034/kWh~~	NA
	2	*$0.010/kWh* ~~$0.011/kWh~~	*$0.018/kWh* ~~$0.021/kWh~~	*$0.027/kWh* ~~$0.030/kWh~~	*$0.034/kWh* ~~$0.038/kWh~~	*$0.041/kWh* ~~$0.046/kWh~~	NA
	3	*$0.013/kWh* ~~$0.014/kWh~~	*$0.025/kWh* ~~$0.027/kWh~~	*$0.036/kWh* ~~$0.038/kWh~~	*$0.046/kWh* ~~$0.050/kWh~~	*$0.056/kWh* ~~$0.060/kWh~~	NA
Energy Intensive Primary Rate EIP	1	*$0.001/kWh* ~~$0.005/kWh~~	*$0.002/kWh* ~~$0.010/kWh~~	*$0.002/kWh* ~~$0.014/kWh~~	*$0.003/kWh* ~~$0.018/kWh~~	*$0.004/kWh* ~~$0.021/kWh~~	NA
	2	*$0.003/kWh* ~~$0.009/kWh~~	*$0.005/kWh* ~~$0.017/kWh~~	*$0.008/kWh* ~~$0.025/kWh~~	*$0.010/kWh* ~~$0.032/kWh~~	*$0.012/kWh* ~~$0.039/kWh~~	NA
	3	*$0.005/kWh* ~~$0.010/kWh~~	*$0.009/kWh* ~~$0.019/kWh~~	*$0.013/kWh* ~~$0.027/kWh~~	*$0.016/kWh* ~~$0.035/kWh~~	*$0.020/kWh* ~~$0.042/kWh~~	NA

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

Contributions in Aid of Construction otherwise required by the Company may be suspended for charging sites participating in the PowerMIDrive Public or PowerMIFleet programs.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-5.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 2

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-15.00**

(Continued From Sheet No. C-14.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.

(7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

C4.4 Resale

This provision is closed to resale for general unmetered service, unmetered or metered lighting service and new or expanded service for resale for residential use.

No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, General Service Secondary Time-of-Use Rate GSTU, General Service Secondary Demand Rate GSD, General Service Primary Rate GP, Large General Service Primary Demand Rate GPD, or General Service Primary Time-of-Use Rate GPTU. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate RSM for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision or the Educational Institution Service Provision.

B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.

C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

$~~0.197458~~ *0.214650*	per kWh for all kWh during the months of June - September
$~~0.174375~~ *0.185856*	per kWh for all kWh during the months of October - May

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.

The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

(Continued on Sheet No. C-16.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 3

(Continued From Sheet No. C-17.00)

C4. APPLICATION OF RATES (Contd)

C4.5 Mobile Home Park - Individually Served (Contd)

B. Original Installations of Underground Service Connections From Underground Distribution Systems

The mobile home park owner or an authorized representative shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the ~~additional~~ cost resulting from the installation of the underground service connections. ~~Such~~ *For the route specified by the Company, the* contribution shall be *a flat fee of $1,300. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be a flat fee of $1,300 plus any additional costs in excess of those associated with the route specified by the Company* ~~computed on the basis of $4.50 per foot of required trench measured on the surface of the ground along the route of the cable from the secondary source to a point directly below the customer's meter(s)~~.

The Company shall furnish, install, own and maintain the entire underground electric distribution system including the pre-meter portion of the service lateral cables for new mobile home parks. The trenches for Primary or Secondary main cables will be occupied jointly by facilities of the Company and other utilities where satisfactory agreement for reimbursement of applicable joint facility costs exist between the Company and the other utilities.

Certain related equipment, such as pad-mounted transformers, switching equipment, and service pedestals may be above grade. The area must be suitable for the direct burial installation of cable.

The mobile home park owner or an authorized representative shall provide, own, install and maintain suitable meter supports of a design satisfactory to the Company.

C. If temporary overhead service is installed for the convenience of the mobile home park owner or an authorized representative for construction purposes, such owner or representative shall be required to pay the in-and-out costs of such overhead facilities in the underground area.

D. Where, in the Company's judgment, practical difficulties exist, such as frost or water conditions, rock near the surface, or where there are requirements for deviation from the Company's filed construction standards, the per foot charges included in this rule shall not apply and the contribution in aid of construction shall be equal to the estimated difference in cost between overhead and underground facilities but not less than the contribution calculated under the appropriate per foot charge.

E. The Company may, upon request of the owner and subject to the provisions of this rule, assume ownership of, and incorporate into its electric distribution system, all of an owner's existing electric distribution system and service connection, including distribution lines, transformers, services, meter set assemblies, meters and associated equipment. The Company, on assuming ownership, shall provide individual service and meters for each ultimate consumer. The purchase price to be paid by the Company for such distribution system shall be computed at a rate of $200 per lot for each lot with an installed service connection to the distribution system where the average age of the mobile home park is five years or less. Such rate shall be reduced by $40 per lot for each additional five-year increment in average age.

In cases where the assumption of ownership would require the Company to install new distribution facilities and service connections or modify the existing distribution system, the mobile home park owner or authorized representative may be required to make a deposit or nonrefundable contribution in aid of construction to the Company to cover the cost of such facilities.

(Continued on Sheet No. C-19.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-23.00**

(Continued From Sheet No. C-22.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.3 Restoration of Service (Contd)

The restoration charge and meter relocation charge, if applicable, shall be billed to the customer and shall be paid before service is restored.

An On-Premises Site Visit Charge of $15.00 shall be assessed to the customer if a Company employee is sent to the premises to either serve the customer with a shut-off notification or to shut off service, unless the customer presents evidence that reasonably indicates the claim has been satisfied or is currently in dispute. The charge shall be applied to the customer account. The Company shall not assess this fee twice on the same notice for shutoff.

In case of shutoff of service, the Company shall restore service only after any metering changes, where deemed necessary by the Company, have been made by the Company and after the customer has paid for any unmetered energy used, paid for any damage to Company property, paid the restoration charge and meter relocation charge, installed any necessary devices to protect the Company's facilities and paid all charges as provided in the Company's Electric Rate Book.

A customer who orders a termination and a restoration of service at the same premises within a 12-month period shall be liable for a "turnon" charge of $11.

C5.4 Shutoff Protection Plan for Residential Customers

A. Eligibility

Eligible low-income customers and senior citizen customers may choose to participate in the Shutoff Protection Plan (SPP) in lieu of the applicable Winter Protection Plan as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.131, Winter Protection Plan for Eligible Low-Income Customers, or R 460.132, Winter Protection Plan for Eligible Senior Citizen Customers. For purposes of this Company rule, an eligible low-income customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months and whose household income does not exceed ~~200~~*400*% of the federal poverty guidelines as published by the United States Department of Health and Human Services ~~or who receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid~~. In addition, an eligible senior citizen customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months, is 65 years of age or older, and advises the utility of his or her eligibility. An eligible customer enrolled in the SPP shall be referred to as an SPP Customer. Customers may become eligible for a modified SPP as provided for in Rule C5.4. B.

(Continued on Sheet No. C-24.00)

See Byrom Testimony, Page 40, Lines 1-13; Exhibit A-96 (Gray-1), Item No. 5

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-24.00**

(Continued From Sheet No. C-23.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

B. Enrollment

An eligible customer may enroll at any time of the calendar year in the SPP. Where unauthorized use of utility service has not occurred, to enroll an eligible customer must (1) contact the Company and indicate that they wish to enroll, (2) be able to demonstrate that he or she has made application for state or federal heating assistance, or has a household income that does not exceed ~~200~~*400*% of the federal poverty guidelines as published by the United States Department of Health and Human Services ~~or receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid~~, (3) within 14 days of a customer calling to enroll in the SPP, have completed the enrollment process by paying a minimum down payment of 10% of the total amount owed to the Company at the time of the request to enroll. An eligible customer is not enrolled in the SPP until the enrollment requirements are fulfilled. Customers previously enrolled in the SPP the last twelve months who default may be permitted to re-enroll in a modified SPP payment arrangement, at the discretion of the Company, if they have demonstrated a willingness to satisfy the terms of the payment plan through their payment history or have received assistance that will improve the customer's ability to satisfy the payment arrangements. The modified SPP repayment period shall not exceed 24 months.

Customers who enroll in the SPP who have not been enrolled in the SPP for more than twelve months may not be required to pay a deposit or reconnection fee, if applicable. Customers who enroll in the SPP who were previously enrolled in the SPP in the last twelve months and removed due to default may be required to pay a deposit and a reconnection fee, if applicable.

Where unauthorized use of utility service has occurred, the customer must pay 100% of the portion of charges that are the result of the unauthorized use. Upon receipt of payment, the customer shall be considered eligible if all other eligibility requirements are met. The customer may then enroll under the conditions described previously. The payment of unauthorized use charges may be made at the same time as the down payment of the total amount owed to the Company is made. In the event that the downpayment of the total amount owed to the Company is made without payment of the unauthorized charges at the same time or previously, the payment received shall first be applied to the unauthorized charges.

In the event that an eligible customer has contacted the Company to indicate a wish to enroll but the requirements so described are not met in full, the eligible customer shall then be subject to credit action as though no contact with the Company had occurred. In the event that all Company obligations to shut off service have been met, the eligible customer shall receive a minimum of one communication at least 24 hours prior to shutoff of service.

C. Customer Protection

Once enrolled in the SPP, a utility shall not shut off service to a SPP Customer if the customer pays to the Company a monthly amount equal to 1/12th of the estimated annual bill for the SPP Customer and a Company-specified amount between 1/12th and 1/24th of any remaining delinquent balance owed to the Company at the time of the enrollment. The Company shall have the right to deny or shut off service in accordance with Rules and Regulations of the Company as authorized by the Michigan Public Service Commission outlined in Rule C1.3, Use of Service and in Rule C5.1, Access to Customer's Premises. While the customer is enrolled in the SPP and payments are made by the due date of the amount due shown on the bill, no late payment charges will be assessed. The SPP Customer may participate in the SPP for a maximum period of 24 months or until the delinquent charges are eliminated and the SPP Customer is able to pay his or her regular monthly energy bills.

(Continued on Sheet No. C-25.00)

See Byrom Testimony, Page 40, Lines 1-13; Exhibit A-96 (Gray-1), Item No. 5

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-25.00**

(Continued From Sheet No. C-24.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

C. Customer Protection (Contd)

The estimated annual bill for the SPP Customer and the delinquent balance due may be recalculated periodically by the Company. The Company may also recalculate the estimated annual bill and the delinquent balance due upon the transfer of a balance owed on another account in compliance with Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service.

D. Default

Should a SPP Customer fail to make payment by the due date, a shutoff notice specific to this SPP shall be issued but shall comply with the requirements of Part 8 of Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service. If the SPP Customer makes payment before the date provided for shutoff of service, the customer shall not be considered to be in default but shall remain in the SPP. If the SPP Customer makes payment after this date, the SPP Customer shall be in default and shall be removed from the SPP. The customer shall be subject to shutoff, provided the 24-hour notice was made by the Company.

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.131 and R 460.132, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Residential Customers electing a non-transmitting meter shall be served on Residential Service Secondary Non-Transmitting Meter Rate RSM. Non-Residential Customers served on General Service Secondary Rate GS have the option to choose a non-transmitting meter. In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Customers electing a non-transmitting meter will pay the following charges per premises or billing meter:

Up Front Charge:	~~$69.39~~	~~a one-time charge per billing meter per request if the notice is given before the transmitting meter is installed~~
	~~OR~~	
	$~~123.91~~ *216.22*	a one-time charge per billing meter per request ~~if the notice is given after the transmitting meter is installed~~
Monthly Charge:	$~~3.00~~ *3.09*	per month at each premises as defined in Rule B1., Technical Standards for Electric Service. Multiple metered units shall be charged per billing meter.

All standard charges and provisions of the customer's applicable tariff shall apply.

(Continued on Sheet No. C-26.00)

See Kelly Testimony, Page 188, Line 22 to Page 190, Line 28; Exhibit A-136 (MPK-26), Page 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-26.20**

(Continued From Sheet No. C-26.10)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS

C6.1 Overhead Extension Policy

Applications for electric service which require the construction of an overhead distribution system shall be granted under the following conditions:

A. Residential Customers

The Company shall construct single-phase distribution line extensions at its own cost a distance of 600 feet, for each residential dwelling.

The length of the distribution line extension shall be measured from the nearest point of connection to the Company's facilities from which the extension can be made to the point from which the service line to the customer shall be run.

Distribution line extensions in excess of the above 600 feet shall require a deposit for the estimated cost of such excess footage. The required deposit for such excess footage shall be $3.50 per lineal foot less 25%.

The Company shall make a one-time refund, five years from the completion date of the extension or upon completion of the customer's construction, whichever the customer chooses, of $1,000 for each additional residential customer and/or three times the estimated annual revenue for each additional General Service customer who connects directly to the line for which a deposit was required. Refund allowances shall first be credited against the 25% reduction before a refund is made to the customer based on the customer's cash deposit. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy. Total refund shall not exceed the amount of the original deposit.

B. Installations of Overhead Service Connection - Residential

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the cost resulting from the installation of an overhead service connection. For the route specified by the Company, the contribution shall be a flat fee of $1,300. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be a flat fee of $1,300 plus any additional costs in excess of those associated with the route specified by the Company.

(Continued on Sheet No. C-27.00)

See Partlan Testimony, Page 12, Line 8 to Page 16, Line 9; Exhibit A-96 (Gray-1), Item No. 7

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-27.00**

(Continued From Sheet No. C-26.20)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

~~B.~~*C.* General Service Customers

The Company shall construct single-phase and three-phase distribution line extensions, at its own cost when the cost of such extension does not exceed three times the estimated annual revenue from the customer(s) to be immediately served.

Extensions with costs in excess of three times the estimated annual revenue shall require a deposit from the customer.

(1) Original Customers

At the end of the first complete 12-month period beginning three months following the date the line extension is completed, the Company shall refund to the depositor three times the amount that actual revenue exceeds the original revenue estimate. If the actual revenue exceeds the estimated revenue, the actual revenue then becomes the base upon which future refund calculations are to be made during the remainder of the five year refund period.

(2) Additional Connected Customers

The Company shall refund $1,000 for each residential customer and/or three times the estimated annual revenue for each General Service customer who connects directly to the line for which a deposit was required. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not be made until the original customer(s) or equivalent is actually connected to the extension. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

D. Installations of Overhead Service Connection - General Service

The developer or customer shall be required to make a refundable contribution in aid of construction to the Company, to cover the cost resulting from the installation of an overhead service connection. For the route specified by the Company, the contribution shall be a flat fee of $2,200. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be a flat fee of $2,200 plus any additional costs in excess of those associated with the route specified by the Company.

~~C.~~*E.* General

(1) Refundable deposits made with the Company under this rule shall be subject to refund without interest, for a five-year period which begins three months after the line extension is completed. The Company shall have no further obligation to refund any remaining portion of line extension deposits.

(2) Each extension shall be a separate, distinct unit and any further extension therefrom shall have no effect upon the agreements under which existing extensions were constructed.

(3) Refunds cannot exceed the refundable portion of the deposit.

(4) Estimated construction costs shall exclude services and meters.

(5) The applicant shall furnish, without cost to the Company, all necessary rights-of-way and tree trimming permits, in a form satisfactory to the Company. If the applicant is unable to secure rights-of-way and permits, in a form satisfactory to the Company, the Company may extend its distribution system along an alternate route selected by the Company, and may require the applicant to pay all additional costs incurred.

(Continued on Sheet No. C-28.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-28.00**

(Continued From Sheet No. C-27.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

~~C.~~ *E.* General (Contd)

(6) The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct overhead electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

(7) Contributions in Aid of Construction otherwise required by the Company may be suspended for charging sites participating in the PowerMIDrive Public or PowerMIFleet programs.

(8) All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

(9) Any charges, deposits or contributions may be required In Advance of commencement of construction.

C6.2 Underground Policy

A. General

This rule sets forth the conditions under which the Company shall install direct burial underground electric distribution systems and underground service connections for residential and General Service customers. For the purpose of this rule, such underground distribution facilities are defined as those facilities operated at 15,000 Volts or less phase to ground wye connected or 20,000 Volts or less phase to phase delta connected.

The general policy of the Company is that real estate developers, property owners or other applicants for underground service shall make a contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.
Methods for determining this cost differential for specific classifications of service are provided herein. In cases, where the nature of service or the construction conditions are such that these conditions are not applicable, the general policy stated above shall apply.

In cases where the Company does not require underground electric distribution systems and/or underground service connections, but is required to underground such facilities by state or local law or regulation, the Company may adjust the contribution in aid of construction to account for such requirement.

It shall be mandatory that all original electric distribution systems installed in new residential subdivisions and in existing residential subdivisions in which overhead electric distribution facilities have not already been constructed be placed underground, except that a lot within a subdivision facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area. It shall also be mandatory that all original service connections installed to serve one-family or two-family dwellings from an underground distribution system be placed underground.

Except as otherwise provided in the following paragraph, it shall be mandatory that all new General Service distribution systems and service connections installed in the vicinity of or on the customer's premises to be served, and constructed solely to serve the customer or a group of adjacent customers, be placed underground.

(Continued on Sheet No. C-29.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 7

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-31.00**

(Continued From Sheet No. C-30.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

B. Installations of Underground Distribution Facilities - Residential (Contd)

Where a residential underground distribution system serves lots on one side of a street, the later connection of lots on the other side of the street to that existing system shall be considered as an original installation of a residential underground distribution system for such later-connected lots. Streetlighting, if any, shall be served underground in areas served directly by residential underground distribution systems. The character and location of the streetlighting cables, if any, and all equipment constituting the residential underground distribution system, shall conform to specifications prepared by the Company.

Where the underground cable for a residential underground distribution system extends through areas within the subdivision which are undeveloped or consist of lots platted for future use and which are not to be served initially by the system, the front-foot measurement of both sides of the street or easement along which the cable extends through such areas shall be included in determining the contribution of the owner(s) or developer(s) for the residential underground distribution system.

Where the Company and the owner(s) or developer(s) agree that it is desirable to extend the underground cable to the boundary of a subdivision property from a point outside the subdivision a contribution of $7.00 per trench foot shall be required.

(b) Outside of subdivisions

The Company shall extend its Primary or Secondary distribution system from existing overhead or underground facilities. When any such extension is made from an existing overhead system the property owner may be required to provide an easement(s) for extension of the overhead system to a pole on his/her property where transition from overhead to underground can be made.
The customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the estimated total difference in cost between overhead and direct burial underground facilities for all underground facilities required to serve the customer.

(3) Installation of Underground Service Connections

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the ~~additional~~ cost resulting from the installation of an underground service connection. For *the route specified by the Company,* ~~normal installations such~~ *the* contribution shall be ~~computed on the basis of~~ a flat fee of *$1,300* ~~$350.00 for the first 150 linear feet of service from the termination of the Company's facilities at the front or rear property line to a point directly below the customer's meter. Each additional foot of installation in excess of 150 linear feet shall be computed at $4.50 per linear foot. Where special routing of the service lateral is required by the customer, the $4.50 per foot charge will apply to the route of the line as installed~~. *For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be a flat fee of $1,300 plus any additional costs in excess of those associated with the route specified by the Company.*

Where the electric service connection is installed jointly with the gas service line, the per foot charge for all footage, as measured, shall be reduced by 25 cents per foot.

(Continued on Sheet No. C-32.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-32.00**

(Continued From Sheet No. C-31.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

C. Installations of Underground Distribution Facilities - General Service

(1) Installation of Underground Distribution Systems

The Company shall construct single-phase and three-phase distribution line extensions at its own cost, when the cost of such extension, less contributions made under other sections of this rule, does not exceed three times the estimated annual revenue from the customer(s) to be immediately served. Extensions with costs in excess of three times the estimated annual revenue shall require a deposit from the customer.

(2) Installation of Underground Service Connections

The developer or customer shall be required to make a *refundable* contribution in aid of construction, to cover the ~~additional~~ cost resulting from the installation of an underground service connection. *For the route specified by the Company,* ~~The required~~ *the* contribution shall be~~:~~ *a flat fee of $2,200. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be a flat fee of $2,200 plus any additional costs in excess of those associated with the route specified by the Company.*

~~(a) For apartment houses and condominiums, a rate of $6.50 per trench foot.~~

~~(b) For all other General Service customers a rate of $6.50 per trench foot.~~

(Continued on Sheet No. C-33.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-36.00**

(Continued From Sheet No. C-35.00)

C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)

A. Applicability of Clause (Contd)

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

(1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of ~~1.07898~~ *1.07273* applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of $0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full $0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

(2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-6.00.

Should the Company apply lesser factors than those shown on Sheet No. D-6.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-6.00.

C. General Conditions

(1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.

(2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

(3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

(Continued on Sheet No. C-37.00)

See Breuring Testimony Page 19, Lines 12-14; Exhibit A-52 (EMB-6), Line 57; Exhibit A-96 (Gray-1), Item No. 9

~~M.P.S.C. No. 14 - Electric~~
~~Consumers Energy Company~~ ~~Sheet No. C-50.00~~

~~(Continued from Sheet No. C-49.00)~~

~~C10. RENEWABLE ENERGY PLAN (REP) (Contd)~~

~~C10.4 Experimental Advanced Renewable Program Anaerobic Digestion Program (AD Program)~~

~~The purpose of this rule is to develop and test programs to enable the development of Michigan's renewable energy resources. The program is designed to purchase renewable energy from generators utilizing anaerobic digestion technology. The AD Program consists of approximately 2.4 MW.~~

~~A customer participating in the AD Program is required to install and operate an eligible generation system with alternating current capacity of no less than 150 kW and no more than 1.1 MW after serving the customer's usage. The Company reserves the right to extend, modify or terminate the experimental program.~~

~~A customer participating in the AD Program under this rate is not eligible to participate in the Company's Net Metering program with a system contracted to provide output to the Company under the AD Program. Customers with unsatisfactory payment history on their delivery account are not eligible to participate.~~

~~A. Eligible Equipment~~

~~To participate in the program, an individual or entity must own or lease an anaerobic digestion system capable of generating electricity through methane produced from waste that will qualify as a renewable energy resource as defined in 2008 PA 295. Landfill gas or other methane based units do not qualify for this program. The system must transmit all energy generated on the premises by such equipment not being used to serve the customer's load, to the Company's distribution system and sell such energy to the Company. The individual or applicant applying to participate shall be required to provide evidence of eligibility.~~

~~B. Distribution Requirements~~

~~(1) All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including any telecommunication links, if applicable). Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company.~~

~~(2) The Company will determine the particular nature of the voltage in each case. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.~~

~~(3) Energy and Demand Registering Meters are required for each generating unit served under this rate. For a customer with a secondary system in which the Company elects to measure the service on the primary side of any transformers, 3% shall be added for billing purposes from the energy measurements thus made. For a customer with a primary system in which the Company elects to measure the service on the secondary side of any transformers, 3% shall be deducted for billing purposes from the energy measurements thus made.~~

~~(Continued on Sheet No. C-51.00)~~

~~M.P.S.C. No. 14 - Electric~~
~~Consumers Energy Company~~ ~~Sheet No. C-51.00~~

~~(Continued from Sheet No. C-50.00)~~

~~C10. RENEWABLE ENERGY PLAN (REP) (Contd)~~

~~C10.4 Experimental Advanced Renewable Program Anaerobic Digestion Program (AD Program) (Contd)~~

~~B. Distribution Requirements (Contd)~~

~~(4) The customer must meet the Interconnection Standards referenced in Rule B8 of this Electric Rate Book, Interconnection and *Distributed Generation* Standards R 460.*911* - R 460.*992*, for the class of generator installed. Utility testing and approval of the interconnection and execution of a parallel operating agreement must be completed prior to the equipment operating in parallel with the distribution system of the utility.~~

~~(5) The customer is required to obtain the characteristics of service from the Company prior to the installation of equipment. The Company shall provide the characteristics in writing upon request. In the event that the equipment proposed for connection is not compatible with these characteristics, the Company shall have no obligation to modify its distribution system or provide any monetary compensation to the customer. The equipment shall be installed on the same premises to which energy is delivered to the customer, or on land contiguous to the premises to which energy is delivered to the customer that is owned by the customer or which the customer has a documented long-term lease in a format acceptable to the Company.~~

~~(6) Any service facilities shall be dedicated to the generator and the customer if applicable and shall not be shared with those providing service to any other customer. The Company shall determine the characteristics of service. Should the installation of new Company distribution facilities be necessary for the equipment, all costs for the distribution facilities installed may be charged to the applicant in advance of construction as a nonrefundable contribution.~~

~~(7) If, in the sole judgment of the Company, it appears that connection of the equipment and subsequent service through the Company's facilities may cause a safety hazard, endanger the Company facilities or the customer's equipment or to disturb the Company's service to other customers, the Company may refuse or delay connection of the equipment to its facilities.~~

~~C. Allocation~~

~~The Company will award contracts to participating customers through a formal solicitation beginning on April 1, 2014. If necessary to meet the program capacity, a second solicitation will be issued. Customers electing to participate in the AD Program are required to submit an application to the Company in accordance with a notice issued by the Company. Customers must also submit an application fee of $10 per kW capacity applied. The application fee is refundable for applications that are not selected. For customers selected to participate in the program, the application fee will be applied to any costs associated with modifications to the Company's distribution system to allow interconnection of the customer's generator. If there are no distribution modification costs required for interconnection, then the application fee will be applied to any other customer contribution required under the program and the net, if any, refunded back to the customer. In the event the application capacity exceeds the offered capacity, participants who have submitted valid applications will be selected through a random selection process. Application and information concerning the allocation process shall be made available by the Company at http://www.consumersenergy.com/EARP.~~

~~(1) A customer may only submit one application per solicitation for each location.~~

~~(Continued on Sheet No. C-52.00)~~

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-64.30**

(Continued from Sheet No. C-64.20)

C11. SELF-GENERATION, NET METERING, DISTRIBUTED GENERATION AND SIMPLE RENEWABLE PROGRAM (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing

a. Full Service Customers Outflow Credit

Customers will be credited per kWh or per kW of Outflow based on the power supply rates (which include transmission costs) of their Full Service Rate Schedule as shown below, plus the PSCR factor as shown on Tariff Sheet No. D-6.00.

Residential Rates			
Summer	$~~(0.150563)~~	*(0.153790)*	per kWh of On-Peak Outflow between June 1 and September 30
On-Peak Basic	$~~(0.099222)~~	*(0.105260)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RSP	$~~(0.085252)~~	*(0.084027)*	per kWh of all Outflow kWh between October 1 and May 31
	$~~(0.150563)~~	*(0.153790)*	per kWh of On-Peak Outflow between June 1 and September 30
Smart Hours	$~~(0.099222)~~	*(0.105260)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RSH	$~~(0.095326)~~	*(0.097592)*	per kWh of On-Peak Outflow between October 1 and May 31
	$~~(0.082971)~~	*(0.081435)*	per kWh of Off-Peak Outflow between October 1 and May 31
	$~~(0.150563)~~	*(0.153790)*	per kWh of On-Peak Outflow between June 1 and September 30
Nighttime Savers	$~~(0.111465)~~	*(0.117603)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RPM	$~~(0.082008)~~	*(0.095162)*	per kWh of Super Off-Peak Outflow between June 1 and September 30
	$~~(0.095326)~~	*(0.097592)*	per kWh of On-Peak Outflow between October 1 and May 31
	$~~(0.092809)~~	*(0.091545)*	per kWh of Off-Peak Outflow between October 1 and May 31
	$~~(0.071387)~~	*(0.073547)*	per kWh of Super Off-Peak Outflow between October 1 and May 31
Secondary Rates			
Rate GS	$~~(0.105382)~~	*(0.109330)*	per kWh of Outflow during the billing months of June - September
	$~~(0.082299)~~	*(0.080536)*	per kWh of Outflow during the billing months of October - May
Rate GSTU[(1)]	$~~(0.143964)~~	*(0.148743)*	per kWh of On-Peak Outflow during the billing months of June - September
	$~~(0.109833)~~	*(0.115845)*	per kWh of Mid-Peak Outflow during the billing months of June - September
	$~~(0.080255)~~	*(0.086918)*	per kWh of Off-Peak Outflow during the billing months of June - September
	$~~(0.090563)~~	*(0.087957)*	per kWh of On-Peak Outflow during the billing months of October - May
	$~~(0.070953)~~	*(0.071125)*	per kWh of Off-Peak Outflow during the billing months of October - May
Rate GSD[(1)]	$~~(0.033424)~~	*(0.032577)*	per kWh of Outflow during the billing months of June - September
	$~~(0.027323)~~	*(0.023899)*	per kWh of Outflow during the billing months of October - May
	$~~(27.63)~~	*(26.96)*	per kW of Outflow Demand during the billing months of June - September
	$~~(17.07)~~	*(18.05)*	per kW of Outflow Demand during the billing months of October - May
[(1)] Outflow credit will be reduced by the applicable Interruptible Credit for GSTU and GSD customers participating on GSI Provision.			

(Continued on Sheet No. C-64.40)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-64.40**

(Continued from Sheet No. C-64.30)

C11. SELF-GENERATION, NET METERING, DISTRIBUTED GENERATION AND SIMPLE RENEWABLE PROGRAM (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing (Contd)

a. Full Service Customers Outflow Credit (Contd)

Primary Rates			
Rate GP			
Customer Voltage Level 1	~~$(0.093230)~~	*(0.096410)*	per kWh of outflow during the billing months of June - September
	~~$(0.072836)~~	*(0.071781)*	per kWh of outflow during the billing months of October - May
Customer Voltage Level 2	~~$(0.094425)~~	*(0.097643)*	per kWh of outflow during the billing months of June - September
	~~$(0.073764)~~	*(0.072701)*	per kWh of outflow during the billing months of October - May
Customer Voltage Level 3	~~$(0.095479)~~	*(0.098839)*	per kWh of outflow during the billing months of June - September
	~~$(0.074577)~~	*(0.073596)*	per kWh of outflow during the billing months of October - May
Rate GPD[2]			
Customer Voltage Level 1	~~$(0.042727)~~	*(0.040641)*	per kWh of On-Peak Outflow during the billing months of June - September
	~~$(0.027682)~~	*(0.026358)*	per kWh of Off-Peak Outflow during the billing months of June - September
	~~$(25.78)~~	*(25.78)*	per kW of Outflow Demand during the billing months of June - September
	~~$(0.029145)~~	*(0.025486)*	per kWh of On-Peak Outflow during the billing months of October - May
	~~$(0.025104)~~	*(0.022129)*	per kWh of Off-Peak Outflow during the billing months of October - May
	~~$(22.99)~~	*(23.17)*	per kW of Outflow Demand during the billing months of October - May
Customer Voltage Level 2	~~$(0.043240)~~	*(0.041117)*	per kWh of On-Peak Outflow during the billing months of June - September
	~~$(0.028014)~~	*(0.026666)*	per kWh of Off-Peak Outflow during the billing months of June - September
	$(26.12)		per kW of Outflow Demand during the billing months of June - September
	~~$(0.029495)~~	*(0.025784)*	per kWh of On-Peak Outflow during the billing months of October - May
	~~$(0.025405)~~	*(0.022388)*	per kWh of Off-Peak Outflow during the billing months of October - May
	~~$(23.29)~~	*(23.48)*	per kW of Outflow Demand during the billing months of October - May
Customer Voltage Level 3	~~$(0.043667)~~	*(0.041531)*	per kWh of On-Peak Outflow during the billing months of June - September
	~~$(0.028291)~~	*(0.026935)*	per kWh of Off-Peak Outflow during the billing months of June - September
	~~$(26.42)~~	*(26.46)*	per kW of Outflow Demand during the billing months of June - September
	~~$(0.029787)~~	*(0.026044)*	per kWh of On-Peak Outflow during the billing months of October - May
	~~$(0.025656)~~	*(0.022614)*	per kWh of Off-Peak Outflow during the billing months of October - May
	~~$(23.57)~~	*(23.80)*	per kW of Outflow Demand during the billing months of October - May
Rate GPTU			
Customer Voltage Level 1	~~$(0.129361)~~	*(0.125095)*	per kWh of High-Peak Outflow between June 1 and September 30
	~~$(0.114706)~~	*(0.111347)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	~~$(0.090449)~~	*(0.089906)*	per kWh of Low-Peak Outflow between June 1 and September 30
	~~$(0.067951)~~	*(0.067092)*	per kWh of Off-Peak Outflow between June 1 and September 30
	~~$(0.084662)~~	*(0.080562)*	per kWh of High-Peak Outflow between October 1 and May 31
	~~$(0.079992)~~	*(0.074652)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	~~$(0.067868)~~	*(0.062464)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 2	~~$(0.131005)~~	*(0.126691)*	per kWh of High-Peak Outflow between June 1 and September 30
	~~$(0.116169)~~	*(0.112768)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	~~$(0.091604)~~	*(0.091054)*	per kWh of Low-Peak Outflow between June 1 and September 30
	~~$(0.068813)~~	*(0.067949)*	per kWh of Off-Peak Outflow between June 1 and September 30
	~~$(0.085737)~~	*(0.081591)*	per kWh of High-Peak Outflow between October 1 and May 31
	~~$(0.081011)~~	*(0.075606)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	~~$(0.068733)~~	*(0.063261)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 3	~~$(0.132440)~~	*(0.128239)*	per kWh of High-Peak Outflow between June 1 and September 30
	~~$(0.117451)~~	*(0.114145)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	~~$(0.092617)~~	*(0.092165)*	per kWh of Low-Peak Outflow between June 1 and September 30
	~~$(0.069566)~~	*(0.068779)*	per kWh of Off-Peak Outflow between June 1 and September 30
	~~$(0.086674)~~	*(0.082587)*	per kWh of High-Peak Outflow between October 1 and May 31
	~~$(0.081901)~~	*(0.076528)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	~~$(0.069489)~~	*(0.064032)*	per kWh of Off-Peak Outflow between October 1 and May 31

[2] For customers on Rate GPD GI Provision, On-Peak kW Outflow Credit shall be reduced by $8.50 per kW during the billing months of June through September and $7.50 per kW during the billing months of October through May.

(Continued on Sheet No. C-64.50)

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Consumers Energy Company **Sheet No. C-64.50**

(Continued from Sheet No. C-64.40)

C11. SELF-GENERATION, NET METERING, DISTRIBUTED GENERATION AND SIMPLE RENEWABLE PROGRAM (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing (Contd)

a. Full Service Customers Outflow Credit (Contd)

Rate EIP			
Customer Voltage Level 1	$~~(0.181549)~~	*(0.183885)*	per kWh of Critical Peak Outflow between June 1 and September 30
	$~~(0.121032)~~	*(0.122589)*	per kWh of High-Peak Outflow between June 1 and September 30
	$~~(0.107716)~~	*(0.109682)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	$~~(0.085436)~~	*(0.087567)*	per kWh of Low-Peak Outflow between June 1 and September 30
	$~~(0.063507)~~	*(0.064571)*	per kWh of Off-Peak Outflow between June 1 and September 30
	$~~(0.119141)~~	*(0.116006)*	per kWh of Critical Peak Outflow between October 1 and May 31
	$~~(0.079427)~~	*(0.077337)*	per kWh of High-Peak Outflow between October 1 and May 31
	$~~(0.074678)~~	*(0.072141)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	$~~(0.063616)~~	*(0.060448)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 2	$~~(0.183844)~~	*(0.186209)*	per kWh of Critical Peak Outflow between June 1 and September 30
	$~~(0.122563)~~	*(0.124140)*	per kWh of High-Peak Outflow between June 1 and September 30
	$~~(0.109085)~~	*(0.111068)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	$~~(0.086524)~~	*(0.088676)*	per kWh of Low-Peak Outflow between June 1 and September 30
	$~~(0.064309)~~	*(0.065390)*	per kWh of Off-Peak Outflow between June 1 and September 30
	$~~(0.120646)~~	*(0.117475)*	per kWh of Critical Peak Outflow between October 1 and May 31
	$~~(0.080431)~~	*(0.078317)*	per kWh of High-Peak Outflow between October 1 and May 31
	$~~(0.075624)~~	*(0.073053)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	$~~(0.064423)~~	*(0.061213)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 3	$~~(0.185840)~~	*(0.188439)*	per kWh of Critical Peak Outflow between June 1 and September 30
	$~~(0.123893)~~	*(0.125626)*	per kWh of High-Peak Outflow between June 1 and September 30
	$~~(0.110280)~~	*(0.112396)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	$~~(0.087475)~~	*(0.089738)*	per kWh of Low-Peak Outflow between June 1 and September 30
	$~~(0.065006)~~	*(0.066174)*	per kWh of Off-Peak Outflow between June 1 and September 30
	$~~(0.121955)~~	*(0.118887)*	per kWh of Critical Peak Outflow between October 1 and May 31
	$~~(0.081303)~~	*(0.079257)*	per kWh of High-Peak Outflow between October 1 and May 31
	$~~(0.076448)~~	*(0.073930)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	$~~(0.065126)~~	*(0.061947)*	per kWh of Off-Peak Outflow between October 1 and May 31

b. Retail Open Access Customers

The Outflow Credit will be determined by the Retail Service Supplier

(Continued on Sheet No. C-64.60)

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Consumers Energy Company **Sheet No. C-77.00**

(Continued From Sheet No. C-76.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Monthly Rate (Contd)

Rate Options (Contd)

Capacity

The monthly capacity payment will be equal to the number of Zonal Resource Credits ("ZRCs") that MISO determines the seller's QF can supply to the Company for the applicable MISO resource planning period multiplied by the applicable capacity rate expressed in such units of capacity. The current resource planning period is the planning year which runs from June 1st of each year through May 31st of the following year. If no historical generation data is available for the first year of generation a QF shall be assigned the MISO class average capacity credits by technology.

Capacity value paid to QFs does not depend on whether the Company actually obtains ZRCs for such capacity, only that the Company could obtain ZRCs for the QF capacity. Capacity value paid to a QF is in units of $ per ZRC-Month. MISO ZRCs are equal to the project's nameplate capacity (in MW_{AC}) modified by the MISO effective load carrying capacity (ELCC) calculation.

Capacity will be paid based on the average of the methodologies utilized by MISO at the time the QF contract is executed and at the time of capacity delivery from the QF, according to the MISO Business Practices Manual (BPM) calculation method effective at the respective times.

Eligible QFs that meet the requirements of Section C18A (1) or C18A (2) of this Rule can select one of the Energy Rate Options listed below:

Rate Option	**Energy Rate $/kWh**			
1. As Available Rate	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node under a 15-year term then multiplied by 1 plus the line loss adjustment factor of ~~2.32~~*2.24*% for interconnection voltages less than 46 kV or ~~1.33~~*1.36*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh			
2. LMP Energy Rate Forecast (Year 1-5)	A 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be based on actual LMPs as described below. Rates include the line loss adjustment and Administrative Fee.			
	On-Peak Energy Rate Interconnection Voltage <46 kV	**Off-Peak Energy Rate Interconnection Voltage <46 kV**	**On-Peak Energy Rate Interconnection Voltage =46 kV**	**Off-Peak Energy Rate Interconnection Voltage =46 kV**
Year	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
2022	$0.02983	$0.02477	$0.02955	$0.02453
2023	$0.03076	$0.02553	$0.03048	$0.02529
2024	$0.03118	$0.02643	$0.03089	$0.02618
2025	$0.03145	$0.02646	$0.03116	$0.02621
2026	$0.03293	$0.02755	$0.03263	$0.02729
2027	$0.03455	$0.02863	$0.03423	$0.02836
2028	$0.03527	$0.02874	$0.03495	$0.02847
2029	$0.03621	$0.02973	$0.03588	$0.02945
2030	$0.03724	$0.03049	$0.03690	$0.03021
Actual LMP (Year 6-10)	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node under the remaining contract term then multiplied by 1 plus the line loss adjustment factor of ~~2.32~~*2.24*% for interconnection voltages less than 46 kV or ~~1.33~~*1.36*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh.			

(Continued on Sheet No. C-78.00)

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Consumers Energy Company **Sheet No. C-78.00**

(Continued From Sheet No. C-77.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Renewable Energy Credits

Renewable Energy Credits (RECs) are owned by the seller. The Company may purchase RECs from sellers that are willing to sell RECs generated. The Company will enter into a separate agreement with the seller for the purchase of any RECs.

E. Term

For QFs at or below 150kW$_{AC}$ in size who qualify for the Standard Offer based on C18A (1) of this rule, the seller may select a contract length up to 20 years.

For QFs at or below 5MW$_{AC}$ in size who qualify for the Standard Offer based on C18A (2) of this rule, the seller may select to receive a contract length up to 15 years when selecting Rate Option 1, or up to 10 years when selecting Rate Option 2.

All Standard Offer PPAs shall require a minimum contract term of one (1) year, and ~~In~~*in* no event shall the term of any PPA as listed above expire prior to the end of a MISO planning period.

F. Early Termination

Sellers shall be required, based on the options made available by the Company, to select a form of security to cover the financial risk associated with the Company's cost for replacement supply in the event the QF ceases operation prior to the end of the term of the PPA.

Security shall be provided through a letter of credit, one-time escrow payment, or monthly escrow payments.
The amount of security required will be based on the contract capacity and the term of the contract. This early termination security amount will be calculated using the following table:

Contract Term (Years)	**Early Termination Security Amount**
5	$10,000 x Contract Capacity (MW)
10	$30,000 x Contract Capacity (MW)
15	$52,500 x Contract Capacity (MW)
20	$62,500 x Contract Capacity (MW)

G. Execution of Standard PPA

In order to execute the Standard PPA, the Seller must complete all of the general project information requested in the applicable Standard PPA. When all information required in the standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the Seller must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA. When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-2.20**

SURCHARGES

Rate Schedule	Electric Rate Case Demand Response Surcharge (Case No. U-~~21585~~ *21870*) Effective for service rendered on and after ~~April 4, 2025~~ *XXXXXX, XX 2026*
Rate RSP	$~~0.002250~~ *0.002227*/kWh
Rate RSH	~~0.002250~~ *0.002227*/kWh
Rate RPM	~~0.002250~~ *0.002227*/kWh
Rate RSM	~~0.002250~~ *0.002227*/kWh
Rate GS	~~0.002106~~ *0.002035*/kWh
Rate GSTU	~~0.002106~~ *0.002035*/kWh
Rate GSD	~~0.71~~ *0.68*/kW
Rate GP	
Customer Voltage Level 1	~~0.001786~~ *0.001726*/kWh
Customer Voltage Level 2	~~0.001807~~ *0.001746*/kWh
Customer Voltage Level 3	~~0.001825~~ *0.001764*/kWh
Rate GPD	
Customer Voltage Level 1	~~0.80~~ *0.74*/kW
Customer Voltage Level 2	~~0.81~~ *0.76*/kW
Customer Voltage Level 3	~~0.82~~ *0.77*/kW
Rate GPTU	
Customer Voltage Level 1	~~0.001608~~ *0.001531*/kWh
Customer Voltage Level 2	~~0.001628~~ *0.001549*/kWh
Customer Voltage Level 3	~~0.001644~~ *0.001564*/kWh
Rate EIP	
Customer Voltage Level 1	~~0.001365~~ *0.001276*/kWh
Customer Voltage Level 2	~~0.001382~~ *0.001291*/kWh
Customer Voltage Level 3	~~0.001395~~ *0.001304*/kWh
Rate LED	
Customer Voltage Level 1	NA
Customer Voltage Level 2	NA
Customer Voltage Level 3	NA
Rate LTILRR	NA
Rate GSG-2	
Customer Voltage Level 1	NA
Customer Voltage Level 2	NA
Customer Voltage Level 3	NA
Rate GML	~~0.000518~~ *0.000518*/kWh
Rate GUL	~~0.000498~~ *0.000487*/kWh
Rate GUL-LED	~~0.000498~~ *0.000487*/kWh
Rate GU	~~0.001366~~ *0.001338*/kWh
Rate PA	NA
Rate ROA-R	NA
Rate ROA-S	NA
Rate ROA-P	NA

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-2.40**

SURCHARGES

Rate Schedule	Investment Recovery Mechanism (IRM) (Case No. U-21585) Effective for service rendered April 4, 2025 through February 28, 2026	*Investment Recovery Mechanism (IRM) (Case No. U-21870) Effective for service rendered XXXXXX XX, 2026 through April 30, 2027*
Rate RSP	$0.000259/kWh	*$0.001123/kWh*
Rate RSH	0.000259/kWh	*0.001123/kWh*
Rate RPM	0.000259/kWh	*0.001123/kWh*
Rate RSM	0.000259/kWh	*0.001123/kWh*
Rate GS	0.000211/kWh	*0.000858/kWh*
Rate GSTU	0.000211/kWh	*0.000858/kWh*
Rate GSD	0.000151/kWh	*0.000661/kWh*
Rate GP		
Customer Voltage Level 1	0.000013/kWh	*0.000107/kWh*
Customer Voltage Level 2	0.000043/kWh	*0.000164/kWh*
Customer Voltage Level 3	0.000076/kWh	*0.000280/kWh*
Rate GPD		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate GPTU		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate EIP		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate LED		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate LTILRR	NA	*NA*
Rate GSG-2		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate GML	0.000257/kWh	*0.001276/kWh*
Rate GUL	0.001028/kWh	*0.005501/kWh*
Rate GU-LED	0.001028/kWh	*0.005501/kWh*
Rate GU	0.000081/kWh	*0.000369/kWh*
Rate PA	NA	*NA*
Rate ROA-R	Same as Full Service Delivery Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-S	Same as Full Service Delivery Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-P	Same as Full Service Delivery Schedule	*Same as Full Service Delivery Schedule*

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 13; Exhibit A-64 (LMC-7)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-5.00**

SURCHARGES

Rate Schedule	Electric Rate Case Deferral Surcharge (Case No. U-21585) Effective for service rendered April 4, 2025 through April 3, 2026	*Electric Rate Case Deferral Surcharge (Case No. U-21870) Effective for service rendered XXXXXX XX, 2026 through XXXXXX XX, 2027*
Rate RSP	$0.001090/kWh	*$0.001228/kWh*
Rate RSH	0.001090/kWh	*0.001228/kWh*
Rate RPM	0.001090/kWh	*0.001228/kWh*
Rate RSM	0.001090/kWh	*0.001228/kWh*
Rate GS	0.000889/kWh	*0.000938/kWh*
Rate GSTU	0.000889/kWh	*0.000938/kWh*
Rate GSD	0.000638/kWh	*0.000723/kWh*
Rate GP		
Customer Voltage Level 1	0.000055/kWh	*0.000117/kWh*
Customer Voltage Level 2	0.000183/kWh	*0.000180/kWh*
Customer Voltage Level 3	0.000319/kWh	*0.000306/kWh*
Rate GPD		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate GPTU		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate EIP		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate LED		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate LTILRR	NA	*NA*
Rate GSG-2		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate GML	0.001082/kWh	*0.001395/kWh*
Rate GUL	0.004333/kWh	*0.006016/kWh*
Rate GU-LED	0.004333/kWh	*0.006016/kWh*
Rate GU	0.000343/kWh	*0.000404/kWh*
Rate PA	NA	*NA*
Rate ROA-R	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*
Rate ROA-S	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*
Rate ROA-P	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*
Rate ROA-GPD	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 13; Exhibit A-67 (LMC-6)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-14.00**

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 - Non-Transmitting Meter Provision participants.

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

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$0.088450	*$0.016810*	*$0.105260*	per kWh for Off-Peak kWh between June 1 and September 30
~~$0.091516~~	~~$0.007706~~	~~$0.099222~~	
$0.129230	*$0.024560*	*$0.153790*	per kWh for On-Peak kWh between June 1 and September 30
~~$0.139098~~	~~$0.011465~~	~~$0.150563~~	
$0.070608	*$0.013419*	*$0.084027*	per kWh for all kWh between October 1 and May 31
~~$0.079248~~	~~$0.006004~~	~~$0.085252~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$~~0.078955~~ *0.100314*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10

(Continued on Sheet No. D-15.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-15.00**

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

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

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

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

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

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit:	$(8.00)	per customer per month

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

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit:	$~~(30.00)~~ *(42.00)*	per meter per month

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

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

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit:	$(4.00)	per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

(Continued on Sheet No. D-16.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-17.00**

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$~~(1.00)~~ *(0.50)*	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount:	$~~(0.007918)~~ *(0.006373)*	per kWh of Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-18.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-36.00**

RESIDENTIAL SMART HOURS RATE RSH

Availability

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.088450* ~~$0.091516~~	*$0.016810* ~~$0.007706~~	*$0.105260* ~~$0.099222~~	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.129230* ~~$0.139098~~	*$0.024560* ~~$0.011465~~	*$0.153790* ~~$0.150563~~	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak - Winter	*$0.068430* ~~$0.077159~~	*$0.013005* ~~$0.005812~~	*$0.081435* ~~$0.082971~~	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.082007* ~~$0.088715~~	*$0.015585* ~~$0.006611~~	*$0.097592* ~~$0.095326~~	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	~~$0.078955~~ *0.100314*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10

(Continued on Sheet No. D-36.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Original Sheet No. D-36.10**

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Income Assistance Service Provision (RIA):

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

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

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

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

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit:	$(8.00)	per customer per month

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

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit:	$~~(30.00)~~ *(42.00)*	per meter per month

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

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

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit:	$(4.00)	per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

(Continued on Sheet No. D-37.00)

See Byrom Testimony, Page 25, Lines 12-20; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 2

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-38.00**

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$~~(1.00)~~ *(0.50)*	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount:	$~~(0.007918)~~ *(0.006373)*	per kWh of Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-40.00**

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

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

Nature of Service

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	*$0.079965* ~~$0.076716~~	*$0.015197* ~~$0.005292~~	*$0.095162* ~~$0.082008~~	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	*$0.098822* ~~$0.102772~~	*$0.018781* ~~$0.008693~~	*$0.117603* ~~$0.111465~~	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.129230* ~~$0.139098~~	*$0.024560* ~~$0.011465~~	*$0.153790* ~~$0.150563~~	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	*$0.061802* ~~$0.066802~~	*$0.011745* ~~$0.004585~~	*$0.073547* ~~$0.071387~~	per kWh for all Super Off-Peak kWh between October 1 and May 31
Off-Peak - Winter	*$0.076926* ~~$0.086417~~	*$0.014619* ~~$0.006392~~	*$0.091545* ~~$0.092809~~	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.082007* ~~$0.088715~~	*$0.015585* ~~$0.006611~~	*$0.097592* ~~$0.095326~~	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$~~0.078955~~ *0.100314*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-40.50)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-40.50**

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

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

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

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

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

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit:	$(8.00)	per customer per month

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

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit:	$~~(30.00)~~ *(42.00)*	per meter per month

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

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

(Continued on Sheet No. D-41.00)

See Byrom Testimony, Page 25, Lines 12-20; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 3

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-42.00**

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate (Contd)

Device Cycling Program (Contd)

Load management may occur during the summer months of June through August only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a load management event for one load management event during the June through August months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers - Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit: $(5.00) per customer per month during the billing months of June - August

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward $~~(1.00)~~ *(0.50)* per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-43.00**

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate (Contd)

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount	$~~(0.007918)~~ *(0.006373)*	per kWh for Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-44.10**

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer may be transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

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

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$0.070608 ~~$0.079248~~	*$0.013419* ~~$0.006004~~	*$0.084027* ~~$0.085252~~	per kWh for the first 600 kWh per month during the billing months of June - September
$0.129230 ~~$0.139098~~	*$0.024560* ~~$0.011465~~	*$0.153790* ~~$0.150563~~	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$0.070608 ~~$0.079248~~	*$0.013419* ~~$0.006004~~	*$0.084027* ~~$0.085252~~	per kWh for all kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-44.20)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-44.20**

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$~~0.078955~~ *0.100314*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Income Assistance Service Provision (RIA):

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

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

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

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

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit:	$(8.00)	per customer per month

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

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit:	$~~(30.00)~~ *(42.00)*	per meter per month

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

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

(Continued on Sheet No. D-44.30)

See Byrom Testimony, Page 25, Lines 12-20; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 4

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-45.00**

GENERAL SERVICE SECONDARY RATE GS

Availability

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$0.093281	*$0.016049*	*$0.109330*	per kWh for all kWh during the billing months of June - September
~~$0.097639~~	~~$0.007743~~	~~$0.105382~~	
$0.068639	*$0.011897*	*$0.080536*	per kWh for all kWh during the billing months of October - May
~~$0.076879~~	~~$0.005420~~	~~$0.082299~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.063166~~ *0.074477*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Billboard Service Provision

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-46.00**

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit: $~~(0.000923)~~ *(0.001009)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-48.00**

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with ~~any other Demand Response Program or~~ Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.074071* ~~$0.075218~~	*$0.012847* ~~$0.005037~~	*$0.086918* ~~$0.080255~~	per kWh for all Off-Peak kWh during the billing months of June - September
Mid-Peak-Summer	*$0.098737* ~~$0.102027~~	*$0.017108* ~~$0.007806~~	*$0.115845* ~~$0.109833~~	per kWh for all Mid-Peak kWh during the billing months of June - September
On-Peak-Summer	*$0.126776* ~~$0.134569~~	*$0.021967* ~~$0.009395~~	*$0.148743* ~~$0.143964~~	per kWh for all On-Peak kWh during the billing months of June - September
Off-Peak-Winter	*$0.060613* ~~$0.066563~~	*$0.010512* ~~$0.004390~~	*$0.071125* ~~$0.070953~~	per kWh for all Off-Peak kWh during the billing months of October - May
On-Peak -Winter	*$0.074942* ~~$0.084687~~	*$0.013015* ~~$0.005876~~	*$0.087957* ~~$0.090563~~	per kWh for all On-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.063166~~ *0.074477*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-49.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-49.00**

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day - January 1, Memorial Day - Last Monday in May, Independence Day - July 4, Labor Day - First Monday in September, Thanksgiving Day - Fourth Thursday in November and Christmas Day - December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1) Off-Peak Hours 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2) Mid-Peak Hours 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3) On-Peak Hours 2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1) Off-Peak Hours 11:00 PM to 7:00 AM
(2) On-Peak Hours 7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Education Institution Credit: $~~(0.000923)~~ *(0.001009)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-50.00**

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate (Contd)

General Service Secondary Interruptible (GSI) Provision (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year. All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GSI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $~~(0.021295)~~ *(0.021685)* per kWh for all kWh

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-50.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-51.00**

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$22.31	*$4.65*	*$26.96*	per kW for all kW of Peak Demand during the
~~$25.46~~	~~$2.17~~	~~$27.63~~	billing months of June - September
$13.91	*$4.14*	*$18.05*	per kW for all kW of Peak Demand during the
~~$15.14~~	~~$1.93~~	~~$17.07~~	billing months of October - May

Energy Charge:

Non-Capacity

$~~0.033424~~ *0.032577*	per kWh for all kWh during the billing months of June - September
$~~0.027323~~ *0.023899*	per kWh for all kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	$~~0.048648~~ *0.061544*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-52.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-53.00**

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate (Contd)

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit:	$~~(0.000745)~~ *(0.000825)*	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate. This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year. All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GSI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(8.50)	per kW for all kW of Peak Demand during the billing months of June - September
	$(7.50)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. D-53.50)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-55.00**

GENERAL SERVICE PRIMARY RATE GP

Availability

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service customers.

Charges for Customer Voltage Level 3 (CVL3)
Energy Charge:

Non-Capacity	Capacity	Total	
$0.085845	*$0.012994*	*$0.098839*	per kWh for all kWh during the billing months of June - September
~~$0.089071~~	~~$0.006408~~	~~$0.095479~~	
$0.063684	*$0.009912*	*$0.073596*	per kWh for all kWh during the billing months of October - May
~~$0.070092~~	~~$0.004485~~	~~$0.074577~~	

Charges for Customer Voltage Level 2 (CVL2)
Energy Charge:

Non-Capacity	Capacity	Total	
$0.084852	*$0.012791*	*$0.097643*	per kWh for all kWh during the billing months of June - September
~~$0.088106~~	~~$0.006319~~	~~$0.094425~~	
$0.062944	*$0.009757*	*$0.072701*	per kWh for all kWh during the billing months of October - May
~~$0.069341~~	~~$0.004423~~	~~$0.073764~~	

Charges for Customer Voltage Level 1 (CVL1)
Energy Charge:

Non-Capacity	Capacity	Total	
$0.083803	*$0.012607*	*$0.096410*	per kWh for all kWh during the billing months of June - September
~~$0.087002~~	~~$0.006228~~	~~$0.093230~~	
$0.062165	*$0.009616*	*$0.071781*	per kWh for all kWh during the billing months of October - May
~~$0.068477~~	~~$0.004359~~	~~$0.072836~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Pages 8-10

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-56.00**

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $~~0.024779~~ *0.026035* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $~~0.010731~~ *0.011747* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $~~0.002918~~ *0.007451* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Cancels Sixth Revised Sheet No. D-57.00**

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(0.001925)~~ *(0.004541)* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.001438)~~ *(0.004114)* per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.
Educational Institution Credit: $~~(0.000558)~~*(0.000576)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-59.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Demand Charge:

Non-Capacity	Capacity	Total	
$12.30	*$4.71*	*$17.01*	per kW of On-Peak Billing Demand during the billing
~~$15.31~~	~~$2.23~~	~~$17.54~~	months of June - September
$10.63	*$4.37*	*$15.00*	per kW of On-Peak Billing Demand during the billing
~~$13.23~~	~~$2.07~~	~~$15.30~~	months of October - May

Transmission Charge:

Non-Capacity

~~$8.88~~ *9.45*	per kW of On-Peak Billing Demand during the billing months of June - September
~~$8.27~~ *8.80*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.043667~~ *0.041531*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.028291~~ *0.026935*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.029787~~ *0.026044*	per kWh for all On-Peak kWh during the billing months of October - May
~~$0.025656~~ *0.022614*	per kWh for all Off-Peak kWh during the billing months of October - May

(Continued on Sheet No. D-60.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 11-13

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-60.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Demand Charge:

Non-Capacity	Capacity	Total	
$12.18	*$4.64*	*$16.82*	per kW of On-Peak Billing Demand during the billing
~~$15.16~~	~~$2.20~~	~~$17.36~~	months of June - September
$10.52	*$4.30*	*$14.82*	per kW of On-Peak Billing Demand during the billing
~~$13.10~~	~~$2.04~~	~~$15.14~~	months of October - May

Transmission Charge:

Non-Capacity

$~~8.76~~ *9.30*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.15~~ *8.66*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.043240~~ *0.041117*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.028014~~ *0.026666*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.029495~~ *0.025784*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.025405~~ *0.022388*	per kWh for all Off-Peak kWh during the billing months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

Demand Charge:

Non-Capacity	Capacity	Total	
$12.04	*$4.57*	*$16.61*	per kW of On-Peak Billing Demand during the billing
~~$14.98~~	~~$2.17~~	~~$17.15~~	months of June - September
$10.40	*$4.24*	*$14.64*	per kW of On-Peak Billing Demand during the billing
~~$12.94~~	~~$2.01~~	$14.95	months of October - May

Transmission Charge:

Non-Capacity

$~~8.63~~ *9.17*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.04~~ *8.53*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.042727~~ *0.040641*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.027682~~ *0.026358*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.029145~~ *0.025486*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.025104~~ *0.022129*	per kWh for all Off-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 11-13

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-61.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Capacity Charge: $~~7.02~~ *7.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)
Capacity Charge: $~~3.50~~ *3.84* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)
Capacity Charge: $~~1.02~~ *2.53* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-62.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate (Contd)

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.66)~~ *(1.83)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-63.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate (Contd)

Aggregate Peak Demand Service Provision (GAP)

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW. *Notwithstanding the specific requirements outlined in this provision, the Company may, at its sole discretion, allow participation by customers who do not fully meet one or more of the stated eligibility criteria, including but not limited to the number of accounts or demand thresholds.*

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $~~(0.000194)~~ *(0.000204)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-66.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate (Contd)

Interruptible Service Provision - Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges: These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

LMP Energy Charge: MISO Real-Time LMP per kWh for all kWh
Capacity & Transmission Charge: $~~0.032871~~ *0.034131* per kWh for all kWh during the billing months of June - September
$~~0.030146~~ *0.032201* per kWh for all kWh during the billing months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

LMP Energy Charge: MISO Real-Time LMP per kWh for all kWh
Capacity & Transmission Charge: $~~0.031540~~ *0.032600* per kWh for all kWh during the billing months of June - September
$~~0.028315~~ *0.029537* per kWh for all kWh during the billing months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

LMP Energy Charge: MISO Real-Time LMP per kWh for all kWh
Capacity & Transmission Charge: $~~0.029172~~ *0.030167* per kWh for all kWh during the billing months of June - September
$~~0.026113~~ *0.027326* per kWh for all kWh during the billing months of October - May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~1.004~~ *0.986*%
Customer Voltage Level 2	~~1.328~~ *1.359*%	~~2.296~~ *2.247*%
Customer Voltage Level 3	~~3.300~~ *3.268*%	~~7.407~~ *6.502*%

Delivery Charges: These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge
If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-67.10**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Coincident Peak Demand Provision (CPD)

This provision is available to any customer on Rate GPD but limited to the first three customers enrolled in the provision. Customers served under this provision will be charged capacity and transmission through a volumetric on peak energy charge as stated below. This will be charged on all energy consumed during the on peak window, from 11 AM to 7 PM. They will pay the On Peak Demand Charge on all demand during the coincident peak window of 4 PM to 6 PM. Customers served under this provision will be subject to Critical Peak Event Pricing.

Critical Peak Event Determination

A Critical Peak Event occurs when a System Integrity Event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed the full on peak demand charge plus $1.00/kWh during the duration of the event.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	*$0.032328* ~~$0.032171~~	*$0.032328* ~~$0.032171~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.028498* ~~$0.027648~~	*$0.028498* ~~$0.027648~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$12.30 ~~$15.31~~	*$4.71* ~~$2.23~~	*$17.01* ~~$17.54~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$10.63 ~~$13.23~~	*$4.37* ~~$2.07~~	*$15.00* ~~$15.30~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

Transmission Charge:

Non-Capacity	
$~~0.016289~~ *0.017954*	per kWh of On-Peak kWh during the billing months of June - September
$~~0.014945~~ *0.016714*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity	
$~~0.028291~~ *0.026935*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.043667~~ *0.041531*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.025656~~ *0.022614*	per kWh for all Off-Peak kWh during the billing months of October - May
$~~0.029787~~ *0.026044*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$12.30 ~~$15.31~~	*$4.71* ~~$2.23~~	*$17.01* ~~$17.54~~	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of June - September
$10.63 ~~$13.23~~	*$4.37* ~~$2.07~~	*$15.00* ~~$15.30~~	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

(Continued on Sheet No. D-67.20)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-67.20**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.10)

Monthly Rate (Contd)

Coincident Peak Demand Provision (CPD) (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	*$0.031117* ~~$0.031076~~	*$0.031117* ~~$0.031076~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.027397* ~~$0.027142~~	*$0.027397* ~~$0.027142~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$12.18 ~~$15.16~~	*$4.64* ~~$2.20~~	*$16.82* ~~$17.36~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$10.52 ~~$13.10~~	*$4.30* ~~$2.04~~	*$14.82* ~~$15.14~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

Transmission Charge:

Non-Capacity

~~$0.015679~~ *0.017210*	per kWh of On-Peak kWh during the billing months of June - September
~~$0.008036~~ *0.008455*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.028014~~ *0.026666*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.043240~~ *0.041117*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.025405~~ *0.022388*	per kWh for all Off-Peak kWh during the billing months of October - May
~~$0.029495~~ *0.025784*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$12.18 ~~$15.16~~	*$4.64* ~~$2.20~~	*$16.82* ~~$17.36~~	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
$10.52 ~~$13.10~~	*$4.30* ~~$2.04~~	*$14.82* ~~$15.14~~	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	*$0.029002* ~~$0.028949~~	*$0.029002* ~~$0.028949~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.025524* ~~$0.025209~~	*$0.025524* ~~$0.025209~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$12.04 ~~$14.98~~	*$4.57* ~~$2.17~~	*$16.61* ~~$17.15~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$10.40 ~~$12.94~~	*$4.24* ~~$2.01~~	*$14.64* ~~$14.95~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

(Continued on Sheet No. D-67.30)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-67.30**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.20)

Coincident Peak Demand Provision (CPD) (Contd)

Monthly Rate (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd

Charges for Customer Voltage Level 1 (CVL 1) (Cont)

Transmission Charge:

Non-Capacity

$~~0.014572~~ *0.016007*	per kWh of On-Peak kWh during the billing months of June - September
$~~0.013548~~ *0.014879*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.027682~~ *0.026358*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.042727~~ *0.040641*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.025104~~ *0.022129*	per kWh for all Off-Peak kWh during the billing months of October - May
$~~0.029145~~ *0.025486*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$12.04 ~~$14.98~~	*$4.57* ~~$2.17~~	*$16.61* ~~$17.15~~	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
$10.40 ~~$12.94~~	*$4.24* ~~$2.01~~	*$14.64* ~~$14.95~~	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

(Continued on Sheet No. D-68.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-71.00**

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate
Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)
Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.060095* ~~$0.065802~~	*$0.008684* ~~$0.003764~~	*$0.068779* ~~$0.069566~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.080555* ~~$0.087045~~	*$0.011610* ~~$0.005572~~	*$0.092165* ~~$0.092617~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.099739* ~~$0.110513~~	*$0.014406* ~~$0.006938~~	*$0.114145* ~~$0.117451~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.112059* ~~$0.125172~~	*$0.016180* ~~$0.007268~~	*$0.128239* ~~$0.132440~~	per kWh during the calendar months of June - September
Off-Peak - Winter	*$0.056004* ~~$0.065478~~	*$0.008028* ~~$0.004011~~	*$0.064032* ~~$0.069489~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.066878* ~~$0.077240~~	*$0.009650* ~~$0.004661~~	*$0.076528* ~~$0.081901~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.072164* ~~$0.082011~~	*$0.010423* ~~$0.004663~~	*$0.082587* ~~$0.086674~~	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL2)
Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.059401* ~~$0.065101~~	*$0.008548* ~~$0.003712~~	*$0.067949* ~~$0.068813~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.079625* ~~$0.086109~~	*$0.011429* ~~$0.005495~~	*$0.091054* ~~$0.091604~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.098587* ~~$0.109327~~	*$0.014181* ~~$0.006842~~	*$0.112768* ~~$0.116169~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.110764* ~~$0.123837~~	*$0.015927* ~~$0.007168~~	*$0.126691* ~~$0.131005~~	per kWh during the calendar months of June - September
Off-Peak - Winter	*$0.055358* ~~$0.064777~~	*$0.007903* ~~$0.003956~~	*$0.063261* ~~$0.068733~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.066106* ~~$0.076414~~	*$0.009500* ~~$0.004597~~	*$0.075606* ~~$0.081011~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.071330* ~~$0.081138~~	*$0.010261* ~~$0.004599~~	*$0.081591* ~~$0.085737~~	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL1)
Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.058667* ~~$0.064293~~	*$0.008425* ~~$0.003658~~	*$0.067092* ~~$0.067951~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.078642* ~~$0.085033~~	*$0.011264* ~~$0.005416~~	*$0.089906* ~~$0.090449~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.097370* ~~$0.107963~~	*$0.013977* ~~$0.006743~~	*$0.111347* ~~$0.114706~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.109397* ~~$0.122297~~	*$0.015698* ~~$0.007064~~	*$0.125095* ~~$0.129361~~	per kWh during the calendar months of June - September
Off-Peak - Winter	*$0.054675* ~~$0.063969~~	*$0.007789* ~~$0.003899~~	*$0.062464* ~~$0.067868~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065289* ~~$0.075462~~	*$0.009363* ~~$0.004530~~	*$0.074652* ~~$0.079992~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.070449* ~~$0.080130~~	*$0.010113* ~~$0.004532~~	*$0.080562* ~~$0.084662~~	per kWh during the calendar months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$~~7.02~~ *7.10*	per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)
Capacity Charge: $~~3.50~~ *3.84* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)
Capacity Charge: $~~1.02~~ *2.53* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Pages 14-16

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-72.00**

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.66)~~ *(1.83)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Educational Institution Credit: $~~(0.000194)~~ *(0.000204)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-72.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-75.00**

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.50)

Monthly Rate
Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.059461* ~~$0.062133~~	*$0.006713* ~~$0.002873~~	*$0.066174* ~~$0.065006~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.080762* ~~$0.082986~~	*$0.008976* ~~$0.004489~~	*$0.089738* ~~$0.087475~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.101259* ~~$0.104822~~	*$0.011137* ~~$0.005458~~	*$0.112396* ~~$0.110280~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.113117* ~~$0.118309~~	*$0.012509* ~~$0.005584~~	*$0.125626* ~~$0.123893~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	per kWh during the calendar months of June - September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June - September
Critical Peak - Summer Economic Event				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	*$0.055740* ~~$0.062001~~	*$0.006207* ~~$0.003125~~	*$0.061947* ~~$0.065126~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.066469* ~~$0.072882~~	*$0.007461* ~~$0.003566~~	*$0.073930* ~~$0.076448~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.071199* ~~$0.077688~~	*$0.008058* ~~$0.003615~~	*$0.079257* ~~$0.081303~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	per kWh during the calendar months of October - May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October - May
Critical Peak - Winter Economic Event				the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.058781* ~~$0.061476~~	*$0.006609* ~~$0.002833~~	*$0.065390* ~~$0.064309~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.079840* ~~$0.082097~~	*$0.008836* ~~$0.004427~~	*$0.088676* ~~$0.086524~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.100105* ~~$0.103702~~	*$0.010963* ~~$0.005383~~	*$0.111068* ~~$0.109085~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.111826* ~~$0.117056~~	*$0.012314* ~~$0.005507~~	*$0.124140* ~~$0.122563~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	per kWh during the calendar months of June - September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June - September
Critical Peak - Summer Economic Event				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	*$0.055103* ~~$0.061341~~	*$0.006110* ~~$0.003082~~	*$0.061213* ~~$0.064423~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065709* ~~$0.072107~~	*$0.007344* ~~$0.003517~~	*$0.073053* ~~$0.075624~~	per kWh during the calendar months of October - May

High-Peak - Winter	*$0.070384* ~~$0.076866~~	*$0.007933* ~~$0.003565~~	*$0.078317* ~~$0.080431~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	per kWh during the calendar months of October - May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October - May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

(Continued on Sheet No. D-76.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Pages 17-19

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-76.00**

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd)
Power Supply Charges:

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.058058* ~~$0.060715~~	*$0.006513* ~~$0.002792~~	*$0.064571* ~~$0.063507~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.078859* ~~$0.081073~~	*$0.008708* ~~$0.004363~~	*$0.087567* ~~$0.085436~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.098876* ~~$0.102411~~	*$0.010806* ~~$0.005305~~	*$0.109682* ~~$0.107716~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.110453* ~~$0.115605~~	*$0.012136* ~~$0.005427~~	*$0.122589* ~~$0.121032~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	per kWh during the calendar months of June - September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June - September
Critical Peak - Summer Economic Event				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	*$0.054426* ~~$0.060579~~	*$0.006022* ~~$0.003037~~	*$0.060448* ~~$0.063616~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.064902* ~~$0.071212~~	*$0.007239* ~~$0.003466~~	*$0.072141* ~~$0.074678~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.069519* ~~$0.075914~~	*$0.007818* ~~$0.003513~~	*$0.077337* ~~$0.079427~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	per kWh during the calendar months of October - May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October - May
Critical Peak - Winter Economic Event				the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)
Capacity Charge: $~~7.02~~ *7.10* per kW of Maximum Demand

Charge for Customer Voltage Level 2 (CVL 2)
Capacity Charge: $~~3.50~~ *3.84* per kW of Maximum Demand

Charge for Customer Voltage Level 1 (CVL 1)
Capacity Charge: $~~1.02~~ *2.53* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-77.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-77.00**

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Monthly Rate (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Interruptible Credit

Due to the nature of this rate schedule, all customers on this rate schedule shall receive an Interruptible Credit per kWh for all consumption for each calendar month.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(0.66)~~ *(1.83)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-78.20**

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:

Customer Voltage Level 1	$~~10.94~~ *11.27*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$~~11.09~~ *11.43*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$~~11.26~~ *11.61*	per kW of On-Peak Billing Demand for all calendar months

Effective for contracts dated on and after June 7, 2024, the monthly Production Charge is the Cost of New Entry for MISO's Local Resource Zone 7 ("CONE"), as of the time of contract execution. The monthly Production Charge is fixed for the contract term at the rate in effect at the time of contract execution, unless the customer fails to meet the minimum On-Peak Billing Demand required by the Company. Effective for contracts dated on or before June 7, 2024, customers shall pay the monthly Production Charge which was in effect at the time of contract execution.

Transmission Charge:

Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge:

For all energy supplied by the Company, the customer shall be responsible for either the MISO Real-Time or Day Ahead Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh). Customers also enrolled in the Voluntary Large Customer Renewable Program LC-REP (LC-REP) may choose, at the Company's discretion, to have the billing of energy under this Rate Schedule match with the crediting methodology of energy under the LC-REP Program for administrative purposes.

Line losses applied to Energy Charge	
Voltage Level 1	~~3.23~~ *3.08*%
Voltage Level 2	~~4.68~~ *4.25*%
Voltage Level 3	~~6.27~~ *5.27*%

(Continued on Sheet No. D-78.30)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-78.30**

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Monthly Rate (Contd)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$~~1.02~~ *2.53*	per kW of Maximum Demand
Customer Voltage Level 2:	$~~3.50~~ *3.84*	per kW of Maximum Demand
Customer Voltage Level 3:	$~~7.02~~ *7.10*	per kW of Maximum Demand

The Distribution Charges for the Largea Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and *a facilities allowance* specified in the contract for electric service.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(0.66)~~ *(1.83)* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below 0.909, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than 0.909, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of 0.909. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than 0.909, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.909 in accordance with the following table:

Power Factor	***Penalty***
0.700 to 0.909	*$1.14 per Kilovar*
Below 0.700	*$1.14 per Kilovar first 2 months*

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.909, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

(Continued on Sheet No. D-78.40)

See Connolly Testimony, Page 12, Line 13 to Page 13, Line 7; Exhibit A-96 (Gray-1), Item Nos. 14 and 17

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-78.40**

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

~~**Interruptible Service Provision: (Contd)**~~

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

(Continued on Sheet No. D-78.50)

M.P.S.C. No. 14 - Electric
Consumers Energy Company Sheet No. D-80.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM – ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company:

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company:

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-82.00**

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges:

Power Supply Standby Charges:

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500.

Real Power Losses:

Real Power Losses shall be measured based on the transmission loss factor of ~~2.07~~ *2.12*% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~1.004~~ *0.986*%
Customer Voltage Level 2	~~1.328~~ *1.359*%	~~2.296~~ *2.247*%
Customer Voltage Level 3	~~3.300~~ *3.268*%	~~7.407~~ *6.502*%

Delivery Standby Charges:

System Access Charge:	$100.00	per generator installation per month
Charges for Customer Voltage Level 3 (CVL 3)		
Capacity Charge:	$~~7.02~~ *7.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL 2)		
Capacity Charge:	$~~3.50~~ *3.84*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Capacity Charge:	$~~1.02~~ *2.53*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-83.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-83.00**

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges: (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges:

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(0.66)~~ *(1.83)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-83.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-83.10**

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges: (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges:

Transmission Interconnect Credit: $~~(1.02)~~ *(2.53)* per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-84.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-85.00**

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage:

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service:

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage:

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.045804	$0.000000	*$0.045804*	per kWh for all kWh
~~$0.050983~~		~~$0.050983~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-86.00**

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge:

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$~~0.087373~~ *0.124589*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Primary Power Supply Charge:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.022478 ~~$0.025020~~	$0.000000	*$0.022478* ~~$0.025020~~	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge:

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.066586~~ *0.094947*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-90.10**

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~April 4, 2025~~ *XXXXXX XX, 2026*:
Company-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~9.67~~ *10.47*	$~~10.00~~ *10.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~10.19~~ *11.26*	$~~10.68~~ *11.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~10.71~~ *12.06*	$~~11.37~~ *12.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~11.23~~ *12.86*	$~~12.06~~ *13.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~11.75~~ *13.66*	$~~12.75~~ *14.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~12.27~~ *14.46*	$~~13.43~~ *15.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~12.79~~ *15.25*	$~~14.12~~ *16.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~13.31~~ *16.05*	$~~14.81~~ *17.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~13.83~~ *16.85*	$~~15.49~~ *18.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~14.35~~ *17.65*	$~~16.18~~ *19.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~14.87~~ *18.45*	$~~16.87~~ *20.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~15.38~~ *19.24*	$~~17.55~~ *21.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~15.90~~ *20.04*	$~~18.23~~ *22.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~16.42~~ *20.84*	$~~18.92~~ *23.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~16.94~~ *21.64*	$~~19.61~~ *23.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~17.46~~ *22.44*	$~~20.29~~ *24.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~17.98~~ *23.23*	$~~20.98~~ *25.86*
185-194	$~~3.17~~ *2.78*	$0.00	$~~3.17~~ *2.78*	$~~18.50~~ *24.03*	$~~21.67~~ *26.81*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~19.02~~ *24.83*	$~~22.36~~ *27.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~19.54~~ *25.63*	$~~23.04~~ *28.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~20.06~~ *26.43*	$~~23.73~~ *29.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~20.58~~ *27.22*	$~~24.42~~ *30.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~21.10~~ *28.02*	$~~25.11~~ *31.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~21.62~~ *28.82*	$~~25.79~~ *32.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~22.13~~ *29.62*	$~~26.47~~ *33.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~22.65~~ *30.42*	$~~27.16~~ *34.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~23.17~~ *31.22*	$~~27.84~~ *35.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~23.69~~ *32.01*	$~~28.53~~ *36.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~24.21~~ *32.81*	$~~29.22~~ *37.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~24.73~~ *33.61*	$~~29.91~~ *38.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~25.25~~ *34.41*	$~~30.59~~ *39.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~25.77~~ *35.21*	$~~31.28~~ *40.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~26.29~~ *36.00*	$~~31.97~~ *40.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~26.81~~ *36.80*	$~~32.65~~ *41.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~27.33~~ *37.60*	$~~33.34~~ *42.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~27.85~~ *38.40*	$~~34.03~~ *43.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~28.37~~ *39.20*	$~~34.72~~ *44.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~28.89~~ *39.99*	$~~35.40~~ *45.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~29.40~~ *40.79*	$~~36.08~~ *46.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~29.92~~ *41.59*	$~~36.77~~ *47.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~30.44~~ *42.39*	$~~37.46~~ *48.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~30.96~~ *43.19*	$~~38.14~~ *49.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~31.48~~ *43.98*	$~~38.83~~ *50.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~32.00~~ *44.78*	$~~39.52~~ *51.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~32.52~~ *45.58*	$~~40.20~~ *52.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~33.04~~ *46.38*	$~~40.89~~ *53.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~33.56~~ *47.18*	$~~41.58~~ *54.20*

(Continued on Sheet No. D-90.20)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-90.20**

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~April 4, 2025~~ *XXXXXX XX, 2026*:

Customer-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~6.67~~ *7.47*	$~~7.00~~ *7.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~7.19~~ *8.26*	$~~7.68~~ *8.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~7.71~~ *9.06*	$~~8.37~~ *9.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~8.23~~ *9.86*	$~~9.06~~ *10.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~8.75~~ *10.66*	$~~9.75~~ *11.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~9.27~~ *11.46*	$~~10.43~~ *12.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~9.79~~ *12.25*	$~~11.12~~ *13.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~10.31~~ *13.05*	$~~11.81~~ *14.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~10.83~~ *13.85*	$~~12.49~~ *15.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~11.35~~ *14.65*	$~~13.18~~ *16.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~11.87~~ *15.45*	$~~13.87~~ *17.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~12.38~~ *16.24*	$~~14.55~~ *18.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~12.90~~ *17.04*	$~~15.23~~ *19.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~13.42~~ *17.84*	$~~15.92~~ *20.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~13.94~~ *18.64*	$~~16.61~~ *20.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~14.46~~ *19.44*	$~~17.29~~ *21.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~14.98~~ *20.23*	$~~17.98~~ *22.86*
185-194	$~~3.17~~ *2.78*	$0.00	$~~3.17~~ *2.78*	$~~15.50~~ *21.03*	$~~18.67~~ *23.81*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~16.02~~ *21.83*	$~~19.36~~ *24.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~16.54~~ *22.63*	$~~20.04~~ *25.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~17.06~~ *23.43*	$~~20.73~~ *26.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~17.58~~ *24.22*	$~~21.42~~ *27.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~18.10~~ *25.02*	$~~22.11~~ *28.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~18.62~~ *25.82*	$~~22.79~~ *29.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~19.13~~ *26.62*	$~~23.47~~ *30.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~19.65~~ *27.42*	$~~24.16~~ *31.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~20.17~~ *28.22*	$~~24.84~~ *32.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~20.69~~ *29.01*	$~~25.53~~ *33.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~21.21~~ *29.81*	$~~26.22~~ *34.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~21.73~~ *30.61*	$~~26.91~~ *35.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~22.25~~ *31.41*	$~~27.59~~ *36.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~22.77~~ *32.21*	$~~28.28~~ *37.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~23.29~~ *33.00*	$~~28.97~~ *37.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~23.81~~ *33.80*	$~~29.65~~ *38.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~24.33~~ *34.60*	$~~30.34~~ *39.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~24.85~~ *35.40*	$~~31.03~~ *40.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~25.37~~ *36.20*	$~~31.72~~ *41.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~25.89~~ *36.99*	$~~32.40~~ *42.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~26.40~~ *37.79*	$~~33.08~~ *43.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~26.92~~ *38.59*	$~~33.77~~ *44.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~27.44~~ *39.39*	$~~34.46~~ *45.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~27.96~~ *40.19*	$~~35.14~~ *46.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~28.48~~ *40.98*	$~~35.83~~ *47.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~29.00~~ *41.78*	$~~36.52~~ *48.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~29.52~~ *42.58*	$~~37.20~~ *49.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~30.04~~ *43.38*	$~~37.89~~ *50.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~30.56~~ *44.18*	$~~38.58~~ *51.20*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-91.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-94.00**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $~~(6.91)~~ *(7.91)* per month

(Continued on Sheet No. D-94.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-94.20**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~April 4, 2025~~ *XXXXXX XX, 2026*:

Company-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~9.67~~ *10.47*	$~~10.00~~ *10.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~10.19~~ *11.26*	$~~10.68~~ *11.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~10.71~~ *12.06*	$~~11.37~~ *12.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~11.23~~ *12.86*	$~~12.06~~ *13.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~11.75~~ *13.66*	$~~12.75~~ *14.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~12.27~~ *14.46*	$~~13.43~~ *15.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~12.79~~ *15.25*	$~~14.12~~ *16.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~13.31~~ *16.05*	$~~14.81~~ *17.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~13.83~~ *16.85*	$~~15.49~~ *18.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~14.35~~ *17.65*	$~~16.18~~ *19.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~14.87~~ *18.45*	$~~16.87~~ *20.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~15.38~~ *19.24*	$~~17.55~~ *21.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~15.90~~ *20.04*	$~~18.23~~ *22.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~16.42~~ *20.84*	$~~18.92~~ *23.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~16.94~~ *21.64*	$~~19.61~~ *23.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~17.46~~ *22.44*	$~~20.29~~ *24.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~17.98~~ *23.23*	$~~20.98~~ *25.86*
185-194	$~~3.17~~ *2.78*	$0.00	$~~3.17~~ *2.78*	$~~18.50~~ *24.03*	$~~21.67~~ *26.81*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~19.02~~ *24.83*	$~~22.36~~ *27.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~19.54~~ *25.63*	$~~23.04~~ *28.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~20.06~~ *26.43*	$~~23.73~~ *29.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~20.58~~ *27.22*	$~~24.42~~ *30.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~21.10~~ *28.02*	$~~25.11~~ *31.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~21.62~~ *28.82*	$~~25.79~~ *32.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~22.13~~ *29.62*	$~~26.47~~ *33.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~22.65~~ *30.42*	$~~27.16~~ *34.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~23.17~~ *31.22*	$~~27.84~~ *35.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~23.69~~ *32.01*	$~~28.53~~ *36.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~24.21~~ *32.81*	$~~29.22~~ *37.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~24.73~~ *33.61*	$~~29.91~~ *38.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~25.25~~ *34.41*	$~~30.59~~ *39.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~25.77~~ *35.21*	$~~31.28~~ *40.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~26.29~~ *36.00*	$~~31.97~~ *40.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~26.81~~ *36.80*	$~~32.65~~ *41.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~27.33~~ *37.60*	$~~33.34~~ *42.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~27.85~~ *38.40*	$~~34.03~~ *43.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~28.37~~ *39.20*	$~~34.72~~ *44.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~28.89~~ *39.99*	$~~35.40~~ *45.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~29.40~~ *40.79*	$~~36.08~~ *46.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~29.92~~ *41.59*	$~~36.77~~ *47.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~30.44~~ *42.39*	$~~37.46~~ *48.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~30.96~~ *43.19*	$~~38.14~~ *49.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~31.48~~ *43.98*	$~~38.83~~ *50.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~32.00~~ *44.78*	$~~39.52~~ *51.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~32.52~~ *45.58*	$~~40.20~~ *52.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~33.04~~ *46.38*	$~~40.89~~ *53.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~33.56~~ *47.18*	$~~41.58~~ *54.20*

(Continued on Sheet No. D-94.30)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-94.30**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~April 4, 2025~~ *XXXXXX XX, 2026*:

Customer-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~6.67~~ *7.47*	$~~7.00~~ *7.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~7.19~~ *8.26*	$~~7.68~~ *8.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~7.71~~ *9.06*	$~~8.37~~ *9.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~8.23~~ *9.86*	$~~9.06~~ *10.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~8.75~~ *10.66*	$~~9.75~~ *11.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~9.27~~ *11.46*	$~~10.43~~ *12.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~9.79~~ *12.25*	$~~11.12~~ *13.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~10.31~~ *13.05*	$~~11.81~~ *14.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~10.83~~ *13.85*	$~~12.49~~ *15.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~11.35~~ *14.65*	$~~13.18~~ *16.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~11.87~~ *15.45*	$~~13.87~~ *17.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~12.38~~ *16.24*	$~~14.55~~ *18.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~12.90~~ *17.04*	$~~15.23~~ *19.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~13.42~~ *17.84*	$~~15.92~~ *20.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~13.94~~ *18.64*	$~~16.61~~ *20.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~14.46~~ *19.44*	$~~17.29~~ *21.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~14.98~~ *20.23*	$~~17.98~~ *22.86*
185-194	$~~3.17~~ *2.77*	$0.00	$~~3.17~~ *2.77*	$~~15.50~~ *21.03*	$~~18.67~~ *23.80*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~16.02~~ *21.83*	$~~19.36~~ *24.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~16.54~~ *22.63*	$~~20.04~~ *25.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~17.06~~ *23.43*	$~~20.73~~ *26.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~17.58~~ *24.22*	$~~21.42~~ *27.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~18.10~~ *25.02*	$~~22.11~~ *28.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~18.62~~ *25.82*	$~~22.79~~ *29.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~19.13~~ *26.62*	$~~23.47~~ *30.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~19.65~~ *27.42*	$~~24.16~~ *31.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~20.17~~ *28.22*	$~~24.84~~ *32.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~20.69~~ *29.01*	$~~25.53~~ *33.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~21.21~~ *29.81*	$~~26.22~~ *34.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~21.73~~ *30.61*	$~~26.91~~ *35.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~22.25~~ *31.41*	$~~27.59~~ *36.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~22.77~~ *32.21*	$~~28.28~~ *37.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~23.29~~ *33.00*	$~~28.97~~ *37.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~23.81~~ *33.80*	$~~29.65~~ *38.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~24.33~~ *34.60*	$~~30.34~~ *39.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~24.85~~ *35.40*	$~~31.03~~ *40.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~25.37~~ *36.20*	$~~31.72~~ *41.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~25.89~~ *36.99*	$~~32.40~~ *42.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~26.40~~ *37.79*	$~~33.08~~ *43.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~26.92~~ *38.59*	$~~33.77~~ *44.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~27.44~~ *39.39*	$~~34.46~~ *45.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~27.96~~ *40.19*	$~~35.14~~ *46.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~28.48~~ *40.98*	$~~35.83~~ *47.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~29.00~~ *41.78*	$~~36.52~~ *48.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~29.52~~ *42.58*	$~~37.20~~ *49.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~30.04~~ *43.38*	$~~37.89~~ *50.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~30.56~~ *44.18*	$~~38.58~~ *51.20*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-95.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-96.00**

GENERAL SERVICE UNMETERED RATE GU

Availability

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.062184	*$0.007201*	*$0.069385*	per kWh for all kWh
~~$0.067926~~	~~$0.003187~~	~~$0.071113~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$~~0.028437~~ *0.036673*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-97.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. E-22.00**

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-21.00)

RETAILER:

Monthly Rate - Retailer

Transmission Service

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses

The Retailer is responsible for replacing Real Power Losses of ~~7.407~~ *6.502*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER:

Monthly Rate - ROA Customer

ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00, the Power Plant Securitization Charges shown on Sheet No. D-7.00 and the Karn 1 and 2 Securitization Charges Shown on Sheet No. D-7.10.

Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

Customers taking ROA service on December 17, 2020 are excluded from the Karn 1 and 2 Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 17, 2020 or to customers taking service on December 17, 2020 who discontinue taking ROA service any time after December 17, 2020. Customers who discontinue taking ROA service any time after December 17, 2020 and who return to ROA service shall pay the Karn 1 and 2 Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule
E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. E-24.00**

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-23.00)

Metering Requirements

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by a Wireless Under Glass Meter or an Energy Registering Meter, with or without maximum demand registers, of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer with a Maximum Demand of less than 20 kW may elect to install an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with a Maximum Demand of 20 kW or more shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:
Monthly Rate - Retailer

Transmission Service

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses

The Retailer is responsible for replacing Real Power Losses of ~~7.407~~ *6.502*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

(Continued on Sheet No. E-25.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. E-26.00**

RETAIL OPEN ACCESS PRIMARY RATE ROA-P

Availability

Subject to any restrictions, this rate is available to any customer receiving service at a Primary Voltage for the delivery of Power from the Point of Receipt to the Point of Delivery and for resale service in accordance with Rule C4.4, Resale.

This rate is not available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer. This ROA Customer must take service under Retail Open Access Secondary Rate ROA-S.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Service under this rate shall be separately metered. The Retailer shall deliver a flat, fixed amount of power every hour of every day.

Any ROA Customer whose monthly minimum Maximum Demand is less than 1,000 kW must utilize an Aggregator.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements

The load under this tariff shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA customer shall be required to pay the System Access Charge, as provided for under the ROA customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:
Monthly Rate - Retailer

Transmission Service

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses

The Retailer is responsible for replacing Real Power Losses as shown below on the Company's Distribution System associated with the movement of Power and for compensation for losses.

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~1.004~~ *0.986*%
Customer Voltage Level 2	~~1.328~~ *1.359*%	~~2.296~~ *2.247*%
Customer Voltage Level 3	~~3.300~~ *3.268*%	~~7.407~~ *6.502*%

(Continued on Sheet No. E-27.00)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REDACTED

EXHIBITS

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Employee Benefits O&M Expenses
For the Years 2024 and Test Year 12 Months ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-97 (KKG-1)
Page: 1 of 2
Witness: KKGrob
Date: June 2025

Line No.	(a) Description	(b) Actual 12 mos. ended 12/31/2024	(c) Projected 12 mos. Ending 4/30/2027
1	Pension Plans A/B	**($51,785)**	**($45,156)**
2	Defined Company Contribution Plan	**14,774**	**16,507**
3	401 (k) Employees' Savings Plan	**11,396**	**12,731**
4	Active Health Care/Life Insurance/LTD	**29,089**	**33,385**
5	Retiree Health Care and Life Insurance	**(47,536)**	**(48,867)**
6	Other Benefits	**2,601**	**2,780**
7	Pension Volatility Mechanism Deferral	**10,729**	**0**
8	OPEB Volatility Mechanism Deferral	**3,579**	**0**
9	Pension Volatility Mechanism Amortization	**(1,147)**	**(1,912)**
10	OPEB Volatility Mechanism Amortization	**2,330**	**1,813**
11	**Total Expense**	**($25,970)**	**($28,719)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Merit and Inflation
For the Years 2024 and Test Year 12 Months ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-97 (KKG-1)
Page: 2 of 2
Witness: KKGrob
Date: June 2025

Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/207	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Pension Plans A/B**	**$ (51,785)**	**$ (51,785)**	**$ (1,087)**	**$ (52,872)**	**$ (1,269)**	**$ (54,141)**	**$ (433)**	**$9,419**	**$ (45,156)**
2	**Defined Company Contribution Plan**	**$ 14,774**	**$ 14,774**	**$ 310**	**$ 15,084**	**$ 362**	**$ 15,446**	**$ 124**	**$ 937**	**$ 16,507**
3	**401 (k) Employees' Savings Plan**	**$ 11,396**	**$ 11,396**	**$ 239**	**$ 11,635**	**$ 279**	**$ 11,915**	**$ 95**	**$ 721**	**$ 12,731**
4	**Active Health Care/Life Insurance/LTD**	**$ 29,089**	**$ 29,089**	**$ 611**	**$ 29,700**	**$ 713**	**$ 30,413**	**$ 243**	**$ 2,729**	**$ 33,385**
5	**Retiree Health Care and Life Insurance**	**$ (47,536)**	**$ (47,536)**	**$ (998)**	**$ (48,534)**	**$ (1,165)**	**$ (49,699)**	**$ (398)**	**$ 1,230**	**$ (48,867)**
6	**Other Benefits**	**$ 2,601**	**$ 2,601**	**$ 55**	**$ 2,656**	**$ 64**	**$ 2,719**	**$ 22**	**$ 39**	**$ 2,780**
	Other Benefits non labor	**1,714**	**1,714**	**36**	**1,750**	**42**	**1,792**	**14**	**26**	**1,832**
	Other Benefits labor	**887**	**887**	**19**	**906**	**22**	**927**	**7**	**13**	**948**
7	**Pension Volatility Mechanism Deferral**	**$ 10,729**	**$ 10,729**	**$ 225**	**$ 10,954**	**$ 263**	**$ 11,217**	**$ 90**	**($11,307)**	**$ 0**
8	**OPEB Volatility Mechanism Deferral**	**$ 3,579**	**$ 3,579**	**$ 75**	**$ 3,654**	**$ 88**	**$ 3,742**	**$ 30**	**($3,772)**	**$ 0**
9	**Pension Volatility Mechanism Amortization**	**$ (1,147)**	**$ (1,147)**	**$ (24)**	**$ (1,171)**	**$ (28)**	**$ (1,199)**	**$ (10)**	**($703)**	**$ (1,912)**
10	**OPEB Volatility Mechanism Amortization**	**$ 2,330**	**$ 2,330**	**$ 49**	**$ 2,379**	**$ 57**	**$ 2,436**	**$ 19**	**($643)**	**$ 1,813**
11	**Total Employee Benefits O&M Expenses**	$ (25,970)	$ (25,970)	$ (545)	$ (26,515)	$ (636)	$ (27,152)	$ (217)	$ (1,350)	$ (28,719)
	Nonlabor	$ (26,857)	$ (26,857)	$ (564)	$ (27,421)	$ (658)	$ (28,079)	$ (225)	$ (1,363)	$ (29,667)
	Labor	887	887	19	906	22	927	7	13	948

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Rayl	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

CMS Energy

Prepared on January 17, 2025

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2024	2025	2026	2027
Contribution by Plan Year				
Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Nonutility	0.0	0.0	0.0	0.0
Total	$ 0.0	$ 0.0	$ 0.0	$ 0.0
At-Risk?	No	No	No	No
Benefit Restrictions?	No	No	No	No
Participant Count	2,770	2,729	2,649	2,580
PBGC Liability	$ 1,158.1	$ 1,080.7	$ 1,094.1	$ 1,120.9
Market Value of Assets	$ 1,758.4	$ 1,741.4	$ 1,781.1	$ 1,822.6
PBGC Flat Rate Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Projected Benefit Obligation	$ 1,280.9	$ 1,250.7	$ 1,258.6	$ 1,263.9
Market Value of Assets	1,758.4	1,741.4	1,781.1	1,822.6
Funded Status	$ (477.5)	$ (490.7)	$ (522.5)	$ (558.7)
ASC 715 Funded %	137.3%	139.2%	141.5%	144.2%
ASC 715 Accounting Expense				
Utility	$ (42.4)	$ (39.3)	$ (41.4)	$ (40.7)
Nonutility	(1.2)	(1.1)	(1.2)	(1.1)
Total ASC 715 Accounting Expense	$ (43.6)	$ (40.4)	$ (42.6)	$ (41.8)
2020 Settlement Accounting Utility Amortization[1]	5.3	5.3	5.3	5.3
2021 Settlement Accounting Utility Amortization[2]	2.6	2.6	2.6	2.6
2022 Settlement Accounting Utility Amortization[3]	2.7	2.7	2.7	2.7
Total Expense	$ (33.0)	$ (29.8)	$ (32.0)	$ (31.2)
Components of Total Expense				
Service Cost	$ 26.1	$ 23.5	$ 21.8	$ 20.1
Interest Cost	61.3	65.7	66.0	66.2
Expected Return on Assets	(135.3)	(133.3)	(133.3)	(132.1)
Amortization of Outstanding Components	4.3	3.7	2.9	4.0
Total ASC 715 Accounting Expense	$ (43.6)	$ (40.4)	$ (42.6)	$ (41.8)
2020 Settlement Accounting Utility Amortization[1]	5.3	5.3	5.3	5.3
2021 Settlement Accounting Utility Amortization[2]	2.6	2.6	2.6	2.6
2022 Settlement Accounting Utility Amortization[3]	2.7	2.7	2.7	2.7
Total Expense	$ (33.0)	$ (29.8)	$ (32.0)	$ (31.2)
Market Related Value of Assets	$ 1,842.2	$ 1,867.1	$ 1,869.5	$ 1,853.1
Assumptions				
Discount Rate	5.05%	5.73%	5.73%	5.73%
Expected Return on Assets	7.50%	7.30%	7.30%	7.30%
Salary Increases	3.55%	3.70%	3.70%	3.70%

[1] The information related to the 2020 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortization was set up as a regulatory asset for the utility portion of the 2020 settlement loss of $35.5 million at August 31, 2020. As provided by CMS, the amortizations starts in September 2020 over service life of 8.55 years. Additionally, the settlement attributable to the utility portion on December 31, 2020 is $9.8 million, which is also amortized over service of 8.55 years beginning in January 2021. Nonutility portions of the settlement loss are $0.9 million and $0.3 million for August 31, 2020 and December 31, 2020 respectively.

[2] The information related to the 2021 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortization was set up as a regulatory asset for the utility portion of the 2021 settlement loss of $17.6 million at October 31, 2021. As provided by CMS, the amortizations starts in November 2021 over service life of 8.19 years. Additionally, the settlement attributable to the utility portion on December 31, 2021 is $3.3 million, which is also amortized over service of 8.19 years beginning in January 2022. Nonutility portions of the settlement loss are $0.5 million and $0.1 million for October 31, 2021 and December 31, 2021 respectively.

[3] The information related to the 2022 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortizations were set up as regulatory assets for the utility portions of the 2022 settlement losses. The settlements attributable to the utility portions are $3.9 million, $3.7 million, $11.5 million, and $2.5 million as of March 31, 2022, June 30, 2022, September 30, 2022, and December 31, 2022 respectively. As provided by CMS, the amortizations are amortized over service life of 8.11 years beginning in April 2022, July 2022, October 2022, and January 2023 respectively. Nonutility portions of the settlement loss are $0.1 million, $0.1 million, $0.3 million, and $0.1 million for March 31, 2022, June 30, 2022, September 30, 2022, and December 31, 2022 respectively.

CMS Energy

Prepared on January 17, 2025

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2024	2025	2026	2027
Contribution by Plan Year				
Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Nonutility	0.0	0.0	0.0	0.0
Total	$ 0.0	$ 0.0	$ 0.0	$ 0.0
At-Risk?	No	No	No	No
Benefit Restrictions?	No	No	No	No
Participant Count	7,309	7,147	6,975	6,795
PBGC Liability	$ 953.2	$ 853.1	$ 819.5	$ 789.2
Market Value of Assets	$ 1,245.9	$ 1,222.8	$ 1,229.7	$ 1,238.3
PBGC Flat Rate Premium	$ 0.7	$ 0.7	$ 0.7	$ 0.7
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.7	$ 0.7	$ 0.7	$ 0.7
Projected Benefit Obligation	$ 914.4	$ 843.8	$ 810.5	$ 776.9
Market Value of Assets	1,245.9	1,222.8	1,229.7	1,238.3
Funded Status	$ (331.5)	$ (379.0)	$ (419.2)	$ (461.4)
ASC 715 Funded %	136.3%	144.9%	151.7%	159.4%
ASC 715 Accounting Expense				
Utility	$ (38.9)	$ (36.0)	$ (32.7)	$ (27.3)
Nonutility	(4.1)	(3.9)	(3.6)	(3.0)
Total	$ (43.0)	$ (39.9)	$ (36.3)	$ (30.3)
Components of Total Expense				
Service Cost	$ 1.6	$ 1.7	$ 1.7	$ 1.7
Interest Cost	42.6	42.7	40.9	39.1
Expected Return on Assets	(98.6)	(95.1)	(92.6)	(88.8)
Amortization of Outstanding Components	11.4	10.8	13.7	17.7
Total Expense	$ (43.0)	$ (39.9)	$ (36.3)	$ (30.3)
Market Related Value of Assets	$ 1,354.1	$ 1,341.4	$ 1,307.4	$ 1,255.7
Assumptions				
Discount Rate	4.95%	5.59%	5.59%	5.59%
Expected Return on Assets	7.50%	7.30%	7.30%	7.30%
Salary Increases	3.65%	3.80%	3.80%	3.80%

2025-2027 projections reflect the following:

- January 1, 2024 census data.
- PBO discount rate of 5.73% (Plan A) and 5.59% (Plan B) in fiscal 2025+, based on Decebmer 31, 2024 yield curve anlaysis.
- Service Cost effective interest rate of 5.77% (Plan A) and 5.81% (Plan B) in fiscal 2025+, based on December 31, 2024 yield curve analysis.
- Interest Cost effective interest rate of 5.43% (Plan A) and 5.30% (Plan B) in fiscal 2025+, based on December 31, 2024 yield curve analysis.
- Expense is allocated to Utility/Non Utility based on PBO using the preliminary allocation percentages for 2025 expense.
- Contributions are allocated to Utility/Non Utility based on the most recent allocation percentages provided by CMS for the December 2020 contributions.
- December 31, 2024 market assets provided by CMS, with expected returns thereafter.
- Expected and actual asset returns of 7.30% in fiscal 2025+.
- The plans will waive Funding Balance when necessary, in order to maintain a Funded Percentage of at least 80%.
- Other provisions, assumptions and methods are the same as those used for the December 31, 2024 ASC 715 disclosures.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Case No.: U-21870
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CMS Energy

Prepared on January 17, 2025

ASC 715 OPEB Expense Estimates ($ millions)

	2024	2025	2026	2027
Funded Status, January 1				
Accumulated Postretirement Benefit Obligation	$ (899.9)	$ (831.0)	$ (826.0)	$ (818.7)
Plan Assets at Fair Value	$ 1,558.9	$ 1,588.2	$ 1,640.8	$ 1,695.2
Funded Status	$ 659.0	$ 757.2	$ 814.8	$ 876.5
ASC 715 Accounting Expense				
Utility	$ (80.8)	$ (83.9)	$ (86.7)	$ (76.7)
Nonutility	$ (6.7)	$ (6.9)	$ (7.1)	$ (7.0)
Total	$ (87.5)	$ (90.8)	$ (93.8)	$ (83.7)
Components of Total Expense				
Service Cost	$ 11.3	$ 8.4	$ 8.2	$ 7.9
Interest Cost	$ 42.9	$ 43.2	$ 42.9	$ 42.5
Expected Return on Assets	$ (114.8)	$ (111.4)	$ (115.3)	$ (119.0)
Amortization of Net (Gain) or Loss	$ 3.9	$ 2.7	$ 2.2	$ 1.6
Amortization of Prior Service Cost	$ (30.8)	$ (33.7)	$ (31.8)	$ (16.7)
Total Expense	$ (87.5)	$ (90.8)	$ (93.8)	$ (83.7)
Assumptions				
APBO Discount Rate	5.02%	5.69%	5.69%	5.69%
Service Cost Effective Interest Rate	5.12%	5.85%	5.85%	5.85%
Interest Cost Effective Interest Rate	4.91%	5.39%	5.39%	5.39%
Expected Return on Assets	7.50%	7.15%	7.15%	7.15%
Trend Rate—Initial Pre-65	8.00%	8.50%	8.00%	7.50%
Trend Rate—Initial Post-65	8.50%	10.25%	9.75%	9.00%
Trend Rate—Ultimate	4.75%	4.75%	4.75%	4.75%
Trend Rate—Ultimate Year Pre-65	2032	2033	2033	2033
Trend Rate—Ultimate Year Post-65	2032	2033	2033	2033
Expected Contribution	$ 0.0	$ 0.0	$ 0.0	$ 0.0

2025-2027 expense projections reflect the following:

-January 1, 2024 census data.
-APBO discount rate of 5.69% in fiscal 2025+, based on December 31, 2024 yield curve.
-Service Cost effective interest rate of 5.85% in fiscal 2025+, based on December 31, 2024 yield curve.
-Interest Cost effective interest rate of 5.39% in fiscal 2025+, based on December 31, 2024 yield curve.
-December 31, 2024 market assets, provided by CMS
-Other provisions, assumptions and methods are the same as those used for December 31, 2024 ASC 715 disclosures.

EXHIBIT A-100 (KKG-4)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Schedule: B-5.6

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

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
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Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period* 12 Mos Ended 12/31/2025	(d) Projected Bridge Period* 4 Mos Ending 4/30/2026	(e) Projected Bridge Period* 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Asset Preservation	20,940	14,903	8,787	23,690	27,371
2	Other Equipment	357	670	168	838	670
3	Total Facilities & Shared Services	21,298	15,573	8,955	24,528	28,041

		Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
4	Asset Preservation	4,738	18,953	27,371	51,062
5	Other Equipment	168	670	670	1,508
6	Total Facilities & Shared Services	4,905	19,623	28,041	52,569

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

Schedule: B-5.6

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

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 2 of 6
Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year*			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	**Asset Preservation**	**20,940**	**14,903**	**8,787**	**23,690**	**27,371**
	Labor	1,068	835	492	1,327	1,533
	Capitalized E&S	0	0	0	0	0
	Materials	2,115	1,013	598	1,611	1,861
	Contractor	16,669	12,236	7,214	19,450	22,472
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	1,089	820	483	1,303	1,505
	Contingency	0	0	0	0	0
2	**Other Equipment**	**357**	**670**	**168**	**838**	**670**
	Labor	3	7	2	8	7
	Capitalized E&S	0	0	0	0	0
	Materials	254	483	121	603	483
	Contractor	73	134	34	168	134
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	28	47	12	59	47
	Contingency	0	0	0	0	0
3	**Total Facilities & Shared Services**	**21,298**	**15,573**	**8,955**	**24,528**	**28,041**
	Labor	1,071	841	494	1,335	1,539
	Capitalized E&S	0	0	0	0	0
	Materials	2,369	1,496	718	2,214	2,344
	Contractor	16,742	12,370	7,248	19,617	22,606
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	1,116	867	495	1,362	1,552
	Contingency	0	0	0	0	0

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

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

Schedule: B-5.6

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

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
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(a)	(b)	(c)	(d)	(e)
		Projected*		
	4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
4 Asset Preservation	**4,738**	**18,953**	**27,371**	**51,062**
Labor	265	1,061	1,533	2,859
Capitalized E&S	0	0	0	0
Materials	322	1,289	1,861	3,472
Contractor	3,890	15,560	22,472	41,922
Non-Labor Overhead	0	0	0	0
Non-Labor Other	261	1,042	1,505	2,808
Contingency	0	0	0	0
5 Other Equipment	**168**	**670**	**670**	**1,508**
Labor	2	7	7	15
Capitalized E&S	0	0	0	0
Materials	121	483	483	1,086
Contractor	34	134	134	302
Non-Labor Overhead	0	0	0	0
Non-Labor Other	12	47	47	106
Contingency	0	0	0	0
6 Total Facilities & Shared Services	**4,905**	**19,623**	**28,041**	**52,569**
Labor	267	1,068	1,539	2,875
Capitalized E&S	0	0	0	0
Materials	443	1,771	2,344	4,558
Contractor	3,923	15,694	22,606	42,223
Non-Labor Overhead	0	0	0	0
Non-Labor Other	272	1,089	1,552	2,914
Contingency	0	0	0	0

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

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

Schedule: B-5.6

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

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
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Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period* 12 Mos Ending 12/31/2025	(d) Projected Bridge Period* 4 Mos Ending 4/30/2026	(e) Projected Bridge Period* 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Fleet Vehicle Capital Replacement	16,293	19,882	4,282	24,164	20,778
2	Fleet Vehicle Electrification	0	800	0	800	840
3	Fleet Expansion	0	648	0	648	46,070
4	Fleet Business Partner Funded	55	0	0	0	0
5	Fleet Tools - Garage	280	251	86	336	259
6	Total Fleet Services Capital	16,628	21,581	4,368	25,948	67,947

Line No	Description	Projected* 4 Mos Ending 4/30/2025	Projected* 12 Mos Ending 4/30/2026	Projected* 12 Mos Ending 4/30/2027	Projected* 28 Mos Ending 4/30/2027
7	Fleet Vehicle Capital Replacement	5,470	19,494	20,778	45,742
8	Fleet Vehicle Electrification	0	0	840	840
9	Fleet Expansion	0	648	46,070	46,718
10	Fleet Business Partner Funded	0	0	0	0
11	Fleet Tools - Garage	84	253	259	595
12	Total Fleet Services Capital	5,554	20,394	67,947	93,895

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

Schedule: B-5.6

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

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
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Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year*			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	**Fleet Vehicle Capital Replacement**	**16,293**	**19,882**	**4,282**	**24,164**	**20,778**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	13,295	16,616	3,578	20,194	17,364
	Contractor	2,232	2,970	640	3,610	3,104
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	766	296	64	360	310
	Contingency	0	0	0	0	0
2	**Fleet Vehicle Electrification**	**0**	**800**	**0**	**800**	**840**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	800	0	800	840
	Contractor	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
3	**Fleet Expansion**	**0**	**648**	**0**	**648**	**46,070**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	542	0	542	38,501
	Contractor	0	97	0	97	6,883
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	10	0	10	686
	Contingency	0	0	0	0	0
4	**Fleet Business Partner Funded**	**55**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	45	0	0	0	0
	Contractor	8	0	0	0	0
	Non-Labor Overhead		0	0	0	0
	Non-Labor Other	3	0	0	0	0
	Contingency	0	0	0	0	0
5	**Fleet Tools - Garage**	**280**	**251**	**86**	**336**	**259**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	280	251	86	336	259
	Contractor	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
6	**Total Fleet Services Capital**	**16,628**	**21,581**	**4,368**	**25,948**	**67,947**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	13,620	18,208	3,664	21,872	56,964
	Contractor	2,240	3,067	640	3,707	9,987
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	768	306	64	370	996
	Contingency	0	0	0	0	0

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

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

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

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
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Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)
		Projected*			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
7	**Fleet Vehicle Capital Replacement**	**5,470**	**19,494**	**20,778**	**45,742**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4,571	16,291	17,364	38,226
	Contractor	817	2,912	3,104	6,834
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	82	290	310	682
	Contingency	0	0	0	0
8	**Fleet Vehicle Electrification**	**0**	**0**	**840**	**840**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	840	840
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
9	**Fleet Expansion**	**0**	**648**	**46,070**	**46,718**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	542	38,501	39,042
	Contractor	0	97	6,883	6,980
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	10	686	696
	Contingency	0	0	0	0
10	**Fleet Business Partner Funded**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
11	**Fleet Tools - Garage**	**84**	**253**	**259**	**595**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	84	253	259	595
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
12	**Total Fleet Services Capital**	**5,554**	**20,394**	**67,947**	**93,895**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4,655	17,085	56,964	78,704
	Contractor	817	3,009	9,987	13,813
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	82	300	996	1,378
	Contingency	0	0	0	0

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Facilities & Shared Services
($000)

Case No.: U-21870
Exhibit No.: A-101 (QAG-2)
Page: 1 of 2
Witness: QAGuinn
Date: June 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	**Facilities**	**12979**	**11331**
	Labor	2651	2732
	Material	0	0
	Contractor	0	0
	Non-Labor Overhead	0	0
	Non-Labor Other	10328	8599
2	**Real Estate**	**1585**	**2269**
	Labor	1252	1449
	Material	0	0
	Contractor	0	0
	Non-Labor Overhead	0	0
	Non-Labor Other	333	820
3	**Total Operations Support O&M Expenses**	**14564**	**13600**
	Labor	3903	4181
	Material	0	0
	Contractor	0	0
	Non-Labor Overhead	0	0
	Non-Labor Other	10661	9418

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Facilities & Shared Services
($000)

Case No.: U-21870
Exhibit No.: A-101 (QAG-2)
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Witness: QAGuinn
Date: June 2025

Line No.	Description	(a) Actual 12 Mos Ended 12/31/2024	(b) Base O&M for Merit & Inflation 12 Mos Ended 12/31/2024	(c) Merit & Inflation 12 Mos Ending 12/31/2025	(d) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2025	(e) Merit & Inflation 12 Mos Ending 12/31/2026	(f) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2026	(g) Merit & Inflation 4 Mos Ending 4/30/2027	(h) Other Adjustments	(i) Projected O&M 12 Mos Ending 4/30/2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Facilities	12,979	0	0	0	0	0	0	(1,648)	11,331
	Labor	2,651	0	0	0	0	0	0	81	2,732
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0	0	0	0	0
	Non-Labor Other	10,328	0	0	0	0	0	0	(1,729)	8,599
2	Real Estate	1,585	1,252	26	1,278	31	1,309	10	616	2,269
	Labor	1,252	1,252	26	1,278	31	1,309	10	129	1,449
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0	0	0	0	0
	Non-Labor Other	333	0	0	0	0	0	0	487	820
3	Total Operations Support O&M Expenses	14,564	1,252	26	1,278	31	1,309	10	(1,031)	13,600
	Labor	3,903	1,252	26	1,278	31	1,309	10	211	4,181
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0	0	0	0	0
	Non-Labor Other	10,661	0	0	0	0	0	0	(1,242)	9,418

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

Michigan Public Service Commission
Consumers Energy Company
Detailed List of Projected Electric Capital Expenditures
Facilities & Shared Services
(000's)

Case No: U-21870
Exhibit No: A-102 (QAG-3)
Page: 1 of 3
Witness: QAGuinn
Date: June 2025

Line No		Historical Year 12 Mos Ended 12/31/2024	Projected Bridge Period 12 Mos Ended 12/31/2025	Projected Bridge Period 4 Mos Ending 4/30/2026	Projected Bridge Period 16 Mos Ending 4/30/2026	Projected Test Year 12 Mos Ending 4/30/2027
		Electric	Electric	Electric	Electric	Electric
1	**Other Equipment**	**357**	**670**	**168**	**838**	**670**
2	Wellness Equip	29	51	13	64	51
3	Computer Equipment	-	17	4	21	17
4	Print Equipment	37	44	11	55	44
5	Supply Chain Tools & Equipment	212	515	129	644	515
6	Facilities Tools	80	43	11	54	43
7	**Emergent Repairs**	**1,010**	**867**	**477**	**1,344**	**2,706**
8	Asset Preservation - Unplanned Repair	1,010	867	477	1,344	2,706
9	**Asset Replacement**	**9,293**	**4,987**	**1,576**	**6,563**	**8,810**
10	Statewide Paving	928	387	530	916	3,002
11	Statewide Roofing	1,849	1,799	404	2,203	2,290
12	Statewide Mechanical/Electrical	4,027	2,606	514	3,120	2,916
13	Statewide Elevators	400	60	82	142	466
14	Marshall Roadway Paving	1,711	-	-	-	-
15	Furniture	376	136	45	181	136
16	**New Construction**	**2,283**	**-**	**-**	**-**	**-**
17	Lansing Service Center	2,170	-	-	-	-
18	Hastings Service Center	114	-	-	-	-
20	**Renovations**	**8,196**	**8,869**	**6,734**	**15,603**	**15,855**
21	Kalamazoo Service Center	4,551	-	-	-	-
22	Parnall Renovations (P1-3)	3	-	-	-	-
23	Jackson Dispatch	191	-	-	-	-
25	Control/Dispatch Center - Grand Rapids	642	1,988	2,612	4,600	3,390
26	Control/Dispatch Center - Parnall	1,764	3,888	2,259	6,146	12,107
27	South Monroe Interior Renovation	908	2,371	1,815	4,186	86
28	EV Infrastructure	136	623	48	671	272
29	Miscellaneous	**158**	**180**	**-**	**180**	**-**
29	**Total Capital**	**21,298**	**15,573**	**8,955**	**24,528**	**28,041**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Facilities & Shared Services
(000's)
5 Year Historical

Case No: U-21870
Exhibit No: A-102 (QAG-3)
Page: 2 of 3
Witness: QAGuinn
Date: June 2025

	Historical Year 12 Mos Ended 12/31/2020	Historical Year 12 Mos Ended 12/31/2021	Historical Year 12 Mos Ended 12/31/2022	Historical Year 12 Mos Ended 12/31/2023	Historical Year 12 Mos Ended 12/31/2024
	Electric	Electric	Electric	Electric	Electric
Other Equipment	**440**	**797**	**862**	**403**	**357**
Wellness Equip	2	8	98	61	29
Computer Equipment	-	-	18	1	-
Print Equipment	77	15	-	-	37
Real Estate Tools & Equipment	25	42	18	-	-
Supply Chain Tools & Equipment	316	732	727	277	212
Facilities Tools	21	-	-	63	80
Emergent Repairs	**1,678**	**3,564**	**1,523**	**1,011**	**1,010**
Asset Preservation - Unplanned Repair	1,678	3,564	1,523	1,011	1,010
Asset Replacement	**6,209**	**7,326**	**16,020**	**7,425**	**9,293**
Statewide Paving	1,441	2,636	3,781	2,481	928
Statewide Roofing	3,114	2,489	6,533	1,598	1,849
Statewide Mechanical/Electrical	681	975	3,846	2,538	4,027
Statewide Elevators	595	991	1,318	576	400
Marshall Roadway Paving	-	-	-	63	1,711
Furniture	379	236	541	170	376
New Construction	**1,009**	**4,574**	**3,054**	**1,790**	**2,283**
Lansing Service Center	1,006	90	311	1,779	2,170
Hastings Service Center	2	10	3	5	114
Hardy Headquarter Building	132	4,475	2,740	7	-
Renovations	**1**	**253**	**3,387**	**1,714**	**8,196**
Kalamazoo Service Center	1	25	182	482	4,551
Parnall Renovations (P1-3)	-	169	2,715	419	3
Jackson Dispatch	-		292	357	191
Control/Dispatch Center - Grand Rapids	-	-	-	-	642
Control/Dispatch Center - Parnall	-	-	81	-	1,764
South Monroe Interior Renovation	-	-	5	129	908
EV Infrastructure	-	59	113	327	136
Other not included in (QAG-4)	**19,186**	**17,759**	**3,336**	**1,991**	**158**
Total Electric Capital	**28,522**	**34,273**	**28,181**	**14,334**	**21,298**

Michigan Public Service Commission
Consumers Energy Company
Facilities & Shared Services

Case No: U-21870
Exhibit No: A-102 (QAG-3)
Page: 3 of 3
Witness: QAGuinn
Date: June 2025

Line No.	(a)	(b)	(c)	(d)
1	**Project Name**	**Internal Approval**	**Has a Business Case**	**Explanation**
2	Lansing Service Center	YES	YES	
3	Hastings Service Center	YES	YES	
4	Kalamazoo Service Center	YES	YES	
5	Control/Dispatch Center - Grand Rapids	YES	YES	
6	Control/Dispatch Center - Parnall	YES	YES	
7	South Monroe Interior Renovation	YES	YES	
8	EV Infrastructure	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
9	Statewide Paving	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
10	Statewide Roofing	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
11	Statewide Mechanical/Electrical	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
12	Statewide Elevators	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Fleet Responsibility Costs

Case No.: U-21870
Exhibit No.: A-103 (QAG-4)
Page: 1 of 1
Witness: QAGuinn
Date: June 2025

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
1	**Categories**	**2020**	**2021**	**2022**	**2023**	**2024**
2	Licensing	2,738,753	2,840,343	3,145,786	3,192,336	3,039,700
3	Technician	16,878,522	18,902,790	19,788,278	19,585,618	20,577,927
4	Parts	10,656,308	11,649,547	14,557,200	14,755,428	14,803,380
5	Outside Vendor	12,809,528	12,801,491	14,875,779	14,242,537	17,803,960
6	Fuel	12,808,774	17,865,478	25,105,355	20,322,235	19,459,697
7	Support Labor	5,096,942	5,034,713	5,031,440	4,790,586	4,055,665
8	Support Other	3,141,164	3,480,793	4,205,239	3,174,534	4,077,349
9	Total Cost	64,129,991	72,575,154	86,709,077	80,063,275	83,817,677

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Corporation
Detailed List of Projected Electric Capital Expenditures
Fleet Services
For the Years 2024, 2025, 2026 and test year 12 months ending 04/30/2027
($000)

Case No.: U-21870
Exhibit No.: A-104 (QAG-5)
Page: 1 of 2
Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
									Test Year	
Line No.			12 months ended 12/31/2024 Projected Spend	12 months ended 12/31/2024 Projected Unit Count	12 months ending 12/31/2025 Projected Spend	12 months ending 12/31/2025 Projected Unit Count	12 months ending 12/31/2026 Projected Spend	12 months ending 12/31/2026 Projected Unit Count	12 months ending 4/30/2027 Projected Spend	12 months ending 4/30/2027 Projected Unit Count
1	**Fleet Vehicle Capital Replacement Plan**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**16,293**	**312**	**19,882**	**125**	**20,359**	**102**	**20,778**	**89**
	07	SEDAN MID SIZE 4DR	-	-	-	-	-	-	64	**1**
	22	1/2 TON PICKUP	1,076	19	662	9	70	3	370	6
	23	VAN CARGO	1,029	12	334	2	-	-	-	-
	26	1 TON PICKUP WITH SERVICE BODY SHORT CAB	513	7	268	6	-	-	-	-
	27	TRUCK SVC 4WD	-	-	-	-	-	-	-	-
	28	3/4 TON PICKUP	563	15	90	5	662	9	1,374	18
	36	1 TON PICKUP WITH SERVICE BODY	353	6	822	15	348	3	1,606	14
	39	VAN CARGO HI ROOF	-	-	-	-	-	-	-	-
	45	MECHANIC SERVICE TRUCK	578	2	112	1	298	2	102	1
	54	5 YARD DUMP TRUCK SINGLE AXLE	65	1	-	-	-	-	-	-
	59	STAKE RACK TRUCK	-	-	-	-	-	-	149	1
	60	ELECTRIC SERVICE TRUCK	239	74	255	4	-	-	407	3
	61	TRUCK SVC AERIAL 41' 4WD	-	-	-	-	140	1	280	1
	64	SERVICE TRUCK WITH AERIAL DEVICE	1,486	5	3,625	12	3,736	12	3,035	10
	65	TRUCK STREETLIGHT	-	-	-	-	-	-	-	-
	66	TRUCK URD CONST/MAINT	-	-	-	-	-	-	-	-
	75	TRUCK DIG/DRK W/FLATBED	-	-	-	-	-	-	-	-
	77	DIGGER DERRICK TRUCK	2,142	15	5,668	26	5,380	12	4,368	11
	81	TRUCK SVC AERIAL	551	1	-	-			-	-
	85	TANDUM AXLE TRACTOR WITH FIFTH WHEEL HITCH	259	2	-	-	115	1	-	-
	89	BUCKET TRUCK	540	3	2,864	13	6,067	14	7,888	18
	90	FLATBED TRUCK	97	1	84	1			-	-
	96	BUCKET TRUCK	-	-	2,671	6	2,176	5	457	1
	99	MISC. TRUCK	-	-	-	-			-	-
	EQUIPMENT	EQUIPMENT	2,350	22	1,443	7	263	5	541	3
	TRAILERS	TRAILERS	2,667	63	984	18	160	1	137	1
	Lease Buyout - Electric/Common		853	45	-	-	944	34	-	-
	Rental Buyouts		931	20	-	-	-	-	-	-
2	**Fleet Vehicle Electrification**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**-**	**-**	**800**	**21**	**840**	**18**	**840**	**18**
	22	Electric Vehicle Investment	-	-	200	9	240	6	240	6
	64	Altec JEMS	-	-	600	12	600	12	600	12
3	**Fleet Expansion**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**-**	**-**	**648**	**8**	**15,170**	**148**	**46,070**	**229**
	22	1/2T	-	-	-	-	168	3	168	3
	28	3/4T PICKUP	-	-	648	8	3,264	53	3,074	53
	55	10 YARD DUMP	-	-	-	-	445	3	445	3
	42 / 59	FITTING TRUCK	-	-	-	-	1,000	10	1,000	10
	77	DERRICK TRUCK	-	-	-	-	-	-	15,597	43
	89/96	BUCKET TRUCK	-	-	-	-	-	-	13,610	38
	90	REEL TRUCK	-	-	-	-	1,846	10	1,830	10
	E11	TRENCHER	-	-	-	-	2,255	8	2,255	8
	E20	BACKHOE	-	-	-	-	160	1	160	1
	E36	EXCAVATOR	-	-	-	-	1,547	15	1,547	15
	E79	DIRECTIONAL DRILL	-	-	-	-	375	3	375	3
	FLTREEL	SINGLE REEL TRAILER	-	-	-	-	300	3	300	3
	FLTREEL	TRIPLE REEL TRAILER	-	-	-	-	200	2	200	2
	FLTEQUIP	EQUIPMENT TRAILER	-	-	-	-	855	18	855	18
	FLTPOLE	POLE TRAILER	-	-	-	-	855	19	855	19
	Spec 77 Tools		-	-	-	-	1,900	-	1,900	-
	Spec 89/96 Tools		-	-	-	-	-	-	1,900	-
4	**Fleet Business Partner Funded**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**55**	**1**	**-**	**-**	**-**	**-**	**-**	**-**
	28	3/4T PICKUP	$ 55	1	$ -	-	$ -	-	$ -	-
5	**Totals:**		**16,348**	**313**	**21,330**	**154**	**36,369**	**268**	**67,688**	**336**

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

Michigan Public Service Commission
Consumers Energy Company
Fleet Services

Case No.: U-21870
Exhibit No.: A-104 (QAG-5)
Page: 2 of 2
Witness: QAGuinn
Date: June 2025

Line No.	(a)	(b)	(c)	(d)
1	**Project Name**	**Internal Approval**	**Has a Business Cas**	**Explanation**
2	Fleet Vehicle Capital Replacement Plan	YES	NO	Internal funding approval. There is no formal business case, spending level is at historical plus inflation.
3	Fleet Vehicle Electrification	YES	NO	Internal funding approval. There is no formal business case, spending level supports the Fleet Vehicle Capital Replacement plan plus the additional cost for EV units.
4	Fleet Expansion	YES	Yes	See the direct testimony of Company witness Michael P. Kelly
5	Fleet Business Partner Funded	YES	NO	Internal funding approval. There is no formal business case but there are internal support documents for individual unit need.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Corporation
Summary of Fleet Tooling Actual & Projected Capital Expenditures
Fleet Services
For the Years 2024, 2025, 2026 and test year 12 months ending 04/30/2027
($000)

Case No.: U-21870
Exhibit No.: A-105 (QAG-6)
Page: 1 of 1
Witness: QAGuinn
Date: June 2025

Line No.	(a)	(b) 12 months ended 12/31/2024 Historical	(c) 12 months ending 12/31/2025 Projected Spend*	(d) 12 months ending 12/31/2026 Projected Spend*	*Test Year* (e) 12 months ending 4/30/2027 Projected Spend*
1	**Fleet Tools - Garage**				
	Tool Description				
	Shop Equipment	$ 205	$ 206	$ 207	$ 209
	Shop Tools	$ 26	$ 25	$ 25	$ 20
	Diagnostic Tools	$ 49	$ 20	$ 25	$ 30
2	**Fleet Tools Totals:**	**$ 280**	**$ 251**	**$ 257**	**$ 259**

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

New Construction & Renovations

Plan Summaries

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Lansing Service Center

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Lansing Service Center – Health Assessment

Facility Assessment - Lansing Service Center						
Location	Lansing		Maximum Possible Points (80)	Servicable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	MMOM					
Safety						
Compatible Use	0		5	3	2	4
Site Conditions	3		5	3	2	4
Traffic/Site Flow	1		5	3	2	4
Environmental Hazard	1		5	3	2	4
Quality						
Branding	2		5	3	2	4
Workplace Efficiency	3		5	3	2	4
Years since last major systems upgrade	0		5	3	2	4
Cost						
Facility Operating Costs	4		5	3	2	4
Non Facility Cost Impact	4		5	3	2	4
Space Optimization	3		5	3	2	4
Delivery						
Drive Time	3		5	3	2	4
Customer Response	4		5	3	2	4
Sustainability	1		5	3	2	4
Morale						
Employee Pride	2		5	3	2	4
Retention	3		5	3	2	4
Wellness	5		5	3	2	4
Total	***39***		***80***	***48***	***32***	***64***

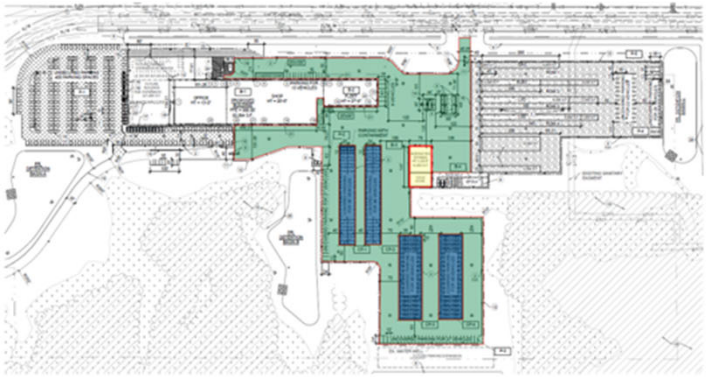
Lansing Service Center – Alternatives Matrix

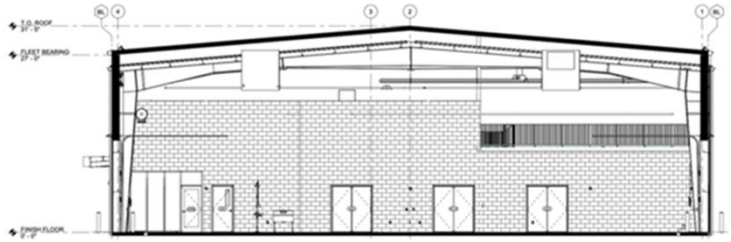
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Alternative Scenario Evaluation Matrix - Lansing Service Center Major Systems Upgrade

	Weight	Build on New Site Score	Renov. Existing Score	Do Nothing Score	Score	COMMENTS
Section 1 - Affordable (50%)						
Operating cost per square foot below statewide average	40%	4.0	3.0	2.0		Current facility operating cost for Lansing is $6.97 per square foot, versus statewide average operating cost of $5.31 per square foot.
Construction cost	10%	1.0	4.0	5.0		
Section 1 - Scenario Average Weighted Score Total (Best = 5):		1.7	1.6	1.3	0.0	
Section 2 - Safe (25%)						
Hazardous Material Abatement (asbestos, lead paint)	5.0%	4.0	3.0	1.0		
Site located outside high crime area	5.0%	4.0	1.0	1.0		
Pedestrian traffic route separated from truck traffic route	2.5%	4.0	1.0	1.0		
Site located outside defined FEMA 100 year flood elevation	10.0%	4.0	1.0	1.0		Current location is 3' below FEMA 100 year flood elev.
Site soils not impacted by previous use (Manufactured Gas Plant)	2.5%	4.0	1.0	1.0		Current location is former Manufactured Gas Plant site
Section 2 - Scenario Average Score Total (Best = 5):		1.0	0.4	0.3	0.0	
Section 3 - Reliable (17.5%)						
Overall score above 72 as measured by Facilites Scorecard	2.5%	4.0	3.0	1.0		Current overall facility score for Lansing is 39
Building size matches operational needs	5.0%	4.0	2.0	2.0		Building fully occupied currently (pre COVID-19)
Improve CAIDI Score > 3%	4.0%	4.0	1.0	1.0		
On Premise start times improved by 5 to 10 minutes	5.0%	4.0	2.0	1.0		Improved material flow and vehicle loading
Drive through vehicle repair bays	2.5%	4.0	2.0	2.0		Improved vehicle repair time, reduced vehicle damage
Section 3 - Scenario Weighted Score Total (Best = 5):		0.6	0.3	0.2	0.0	
Section 4 - Clean (7.5%)						
LEED V4.1 Certification	2.5%	4.0	3.0	1.0		
Stormwater detention and treatment	2.5%	4.0	1.0	1.0		Stormwater currently direct discharge to Grand River
Onsite solar power generation	1.0%	4.0	1.0	1.0		
Section 3 - Scenario Weighted Score Total (Best = 5):		0.2	0.1	0.1	0.0	
TOTAL WEIGHTED VALUE SCORE: (BEST = 5)	100%	3.5	2.4	1.8	0.0	

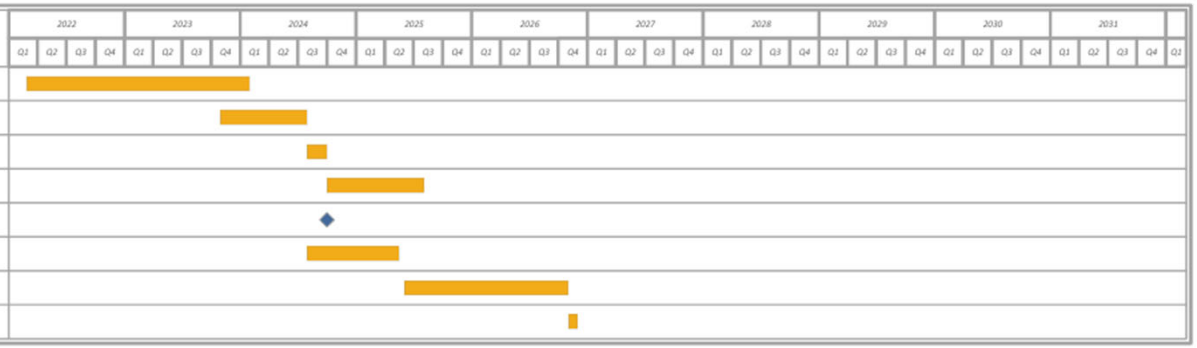
Lansing Service Center – Project Schedule





New Lansing Service Center

ID	Task Name	Start	Finish	Duration
1	Design & Install Water Line Extension	3/1/2022	1/31/2024	502d
2	Programming	11/1/2023	7/31/2024	196d
3	Schematic Design	8/1/2024	9/30/2024	43d
4	Detail Design	10/1/2024	7/31/2025	218d
5	Paid Down Payment on Building	10/1/2024	10/1/2024	0d
6	Obtain State & Local Permits & Approvals	8/1/2024	5/15/2025	206d
7	Construction	6/2/2025	10/30/2026	370d
8	Move-In	11/2/2026	11/30/2026	21d



Hastings Service Center

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Hastings Service Center – Health Assessment

Facility Assessment - Hastings Service Center					
Location	Hastings	Maximum Possible Points (80)	Servicable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	SWOM				
Safety					
Compatible Use	4	5	3	2	4
Site Conditions	4	5	3	2	4
Traffic/Site Flow	2	5	3	2	4
Environmental Hazard	3	5	3	2	4
Quality					
Branding	3	5	3	2	4
Workplace Efficiency	3	5	3	2	4
Years since last major systems upgrade	1	5	3	2	4
Cost					
Facility Operating Costs	0	5	3	2	4
Non Facility Cost Impact	4	5	3	2	4
Space Optimization	2	5	3	2	4
Delivery					
Drive Time	4	5	3	2	4
Customer Response	3	5	3	2	4
Sustainability	3	5	3	2	4
Morale					
Employee Pride	1	5	3	2	4
Retention	3	5	3	2	4
Wellness	1	5	3	2	4
Total	***41***	***80***	***48***	***32***	***64***

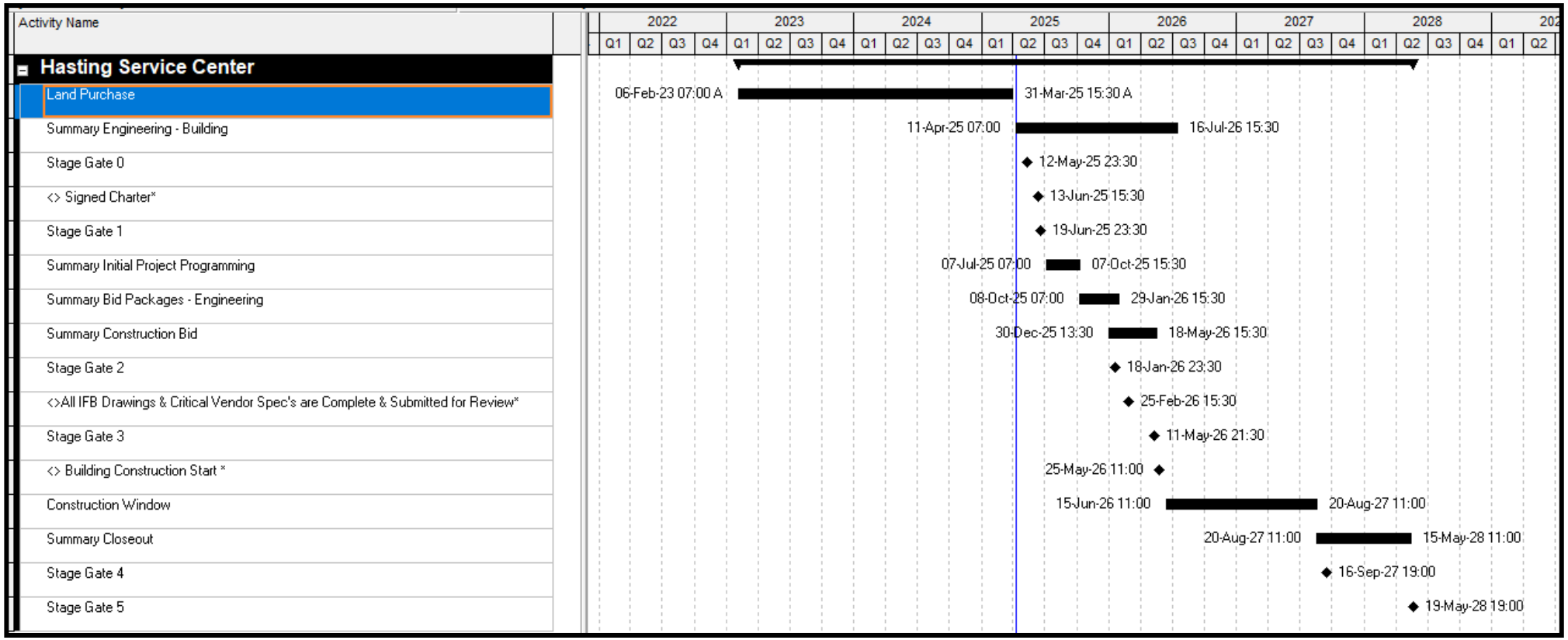
Hastings Service Center – Alternatives Matrix

Consumers Energy
Count on Us

Alternative Scenario Evaluation Matrix - Hastings Service Center Major Systems Upgrade

	Weight	Build on New Site Score	Build on Ex. Site Score	Renov. Existing Score	Do Nothing Score	COMMENTS
Section 1 - Affordable (50%)						
Operating cost per square foot below statewide average	40%	4.0	4.0	2.0	1.0	Current facility operating cost for Hastings is $13.85 per square foot, versus statewide average operating cost of $5.31 per square foot.
Construction cost	10%	2.0	2.0	3.0	4.0	
Section 1 - Scenario Average Weighted Score Total (Best = 5):		1.8	1.8	1.1	0.8	
Section 2 - Safe (12.5%)						
Hazardous Material Abatement (asbestos, lead paint)	2.5%	4.00	4.0	3.0	2.0	
Reduced site congestion and improved vehicular traffic flow	10%	4.00	3.00	1.00	1.00	
Section 2 - Scenario Average Score Total (Best = 5):		0.5	0.4	0.2	0.2	
Section 3 - Reliable (25%)						
Overall score above 72 as measured by Facilites Scorecard	5%	4.0	4.0	3.0	1.0	Current overall facility score for Hastings is 41
On Premise start times improved by 5 to 10 minutes	10%	4.0	4.0	2.0	1.0	Improved material flow and vehicle loading
Drive through vehicle repair bays	5%	4.0	4.0	3.0	3.0	Improved vehicle repair time, reduced vehicle damage
Temporary relocation of operations	5%	4.0	1.0	2.0	4.0	
Section 3 - Scenario Weighted Score Total (Best = 5):		1.0	0.9	0.6	0.5	
Section 4 - Clean (12.5%)						
LEED V4.1 Certification	2.5%	4.0	4.0	2.0	1.0	
Stormwater detention and treatment	2.5%	4.0	4.0	3.0	1.0	Stormwater currently discharged to ditch
Onsite solar power generation	2.5%	4.0	4.0	1.0	1.0	
Municipal Utilities Available	5%	1.0	4.0	4.0	4.0	Available parcels are located outside Hastings urban area, private well and septic will be required
Section 3 - Scenario Weighted Score Total (Best = 5):		0.4	0.5	0.4	0.3	
TOTAL WEIGHTED VALUE SCORE: (BEST = 5)	100%	3.7	3.6	2.2	1.7	

Hastings Service Center – Project Schedule



Kalamazoo Service Center

Plan Summary

Consumers Energy
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Kalamazoo Service Center – Health Assessment

Facility Assessment - Kalamazoo Service Center					
Location	Kalamazoo	Maximum Possible Points (80)	Servicable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	SWOM				
Safety					
Compatible Use	4	5	3	2	4
Site Conditions	5	5	3	2	4
Traffic/Site Flow	3	5	3	2	4
Environmental Hazard	0	5	3	2	4
Quality					
Branding	3	5	3	2	4
Workplace Efficiency	3	5	3	2	4
Years since last major systems upgrade	0	5	3	2	4
Cost					
Facility Operating Costs	5	5	3	2	4
Non Facility Cost Impact	4	5	3	2	4
Space Optimization	1	5	3	2	4
Delivery					
Drive Time	3	5	3	2	4
Customer Response	4	5	3	2	4
Sustainability	1	5	3	2	4
Morale					
Employee Pride	1	5	3	2	4
Retention	4	5	3	2	4
Wellness	5	5	3	2	4
Total	***46***	***80***	***48***	***32***	***64***

Kalamazoo Service Center - Alternatives Summary

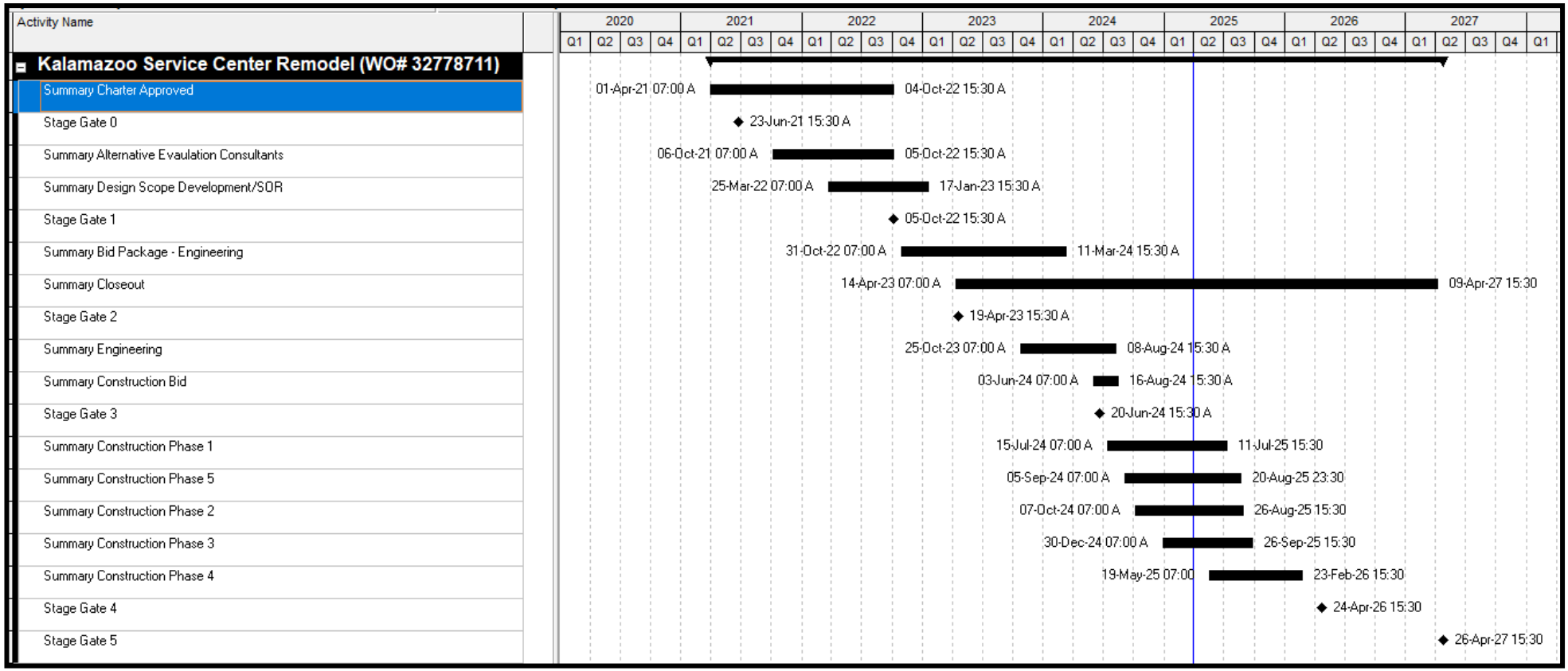
Select icon to view file



Microsoft Edge
PDF Document

Company selected Kalamazoo Alternative Option 1

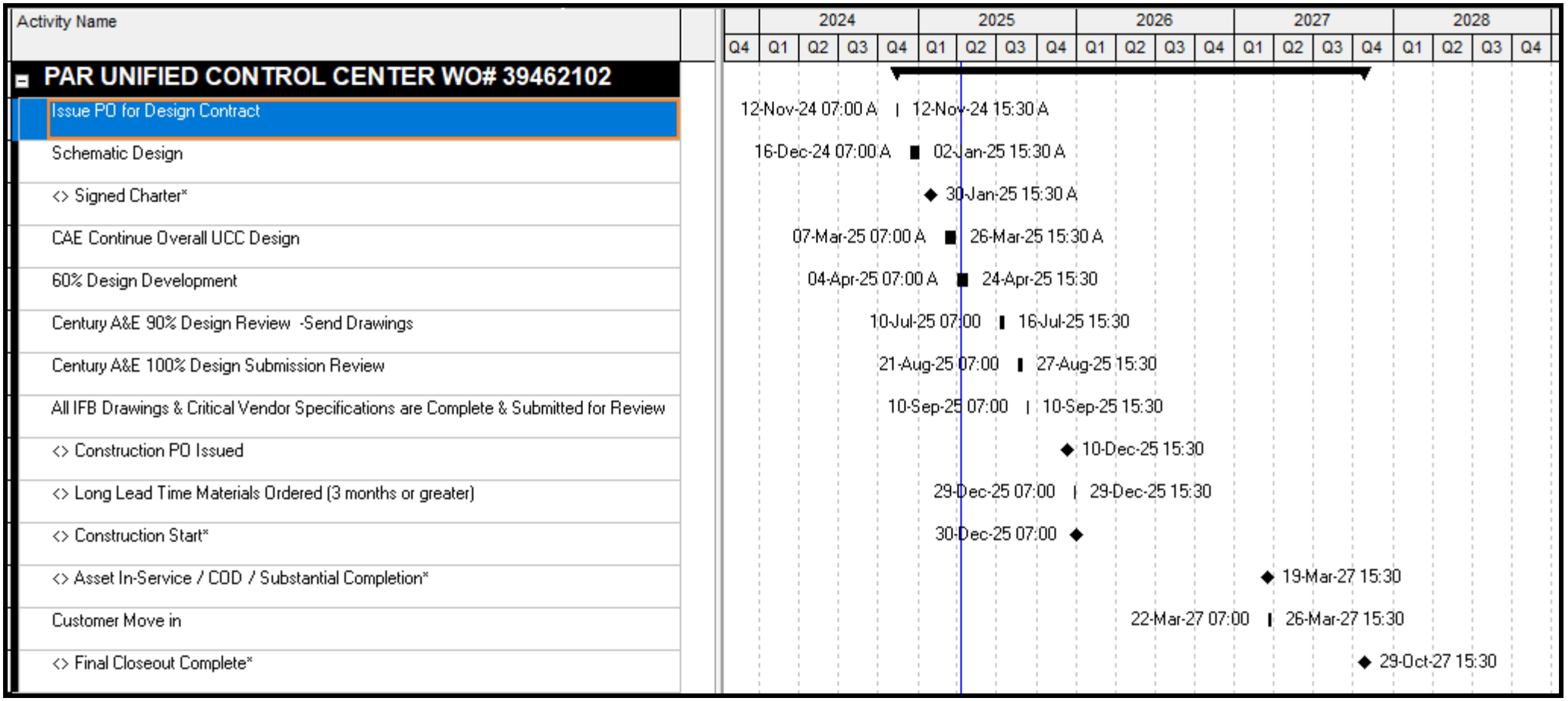
Kalamazoo Service Center – Project Schedule



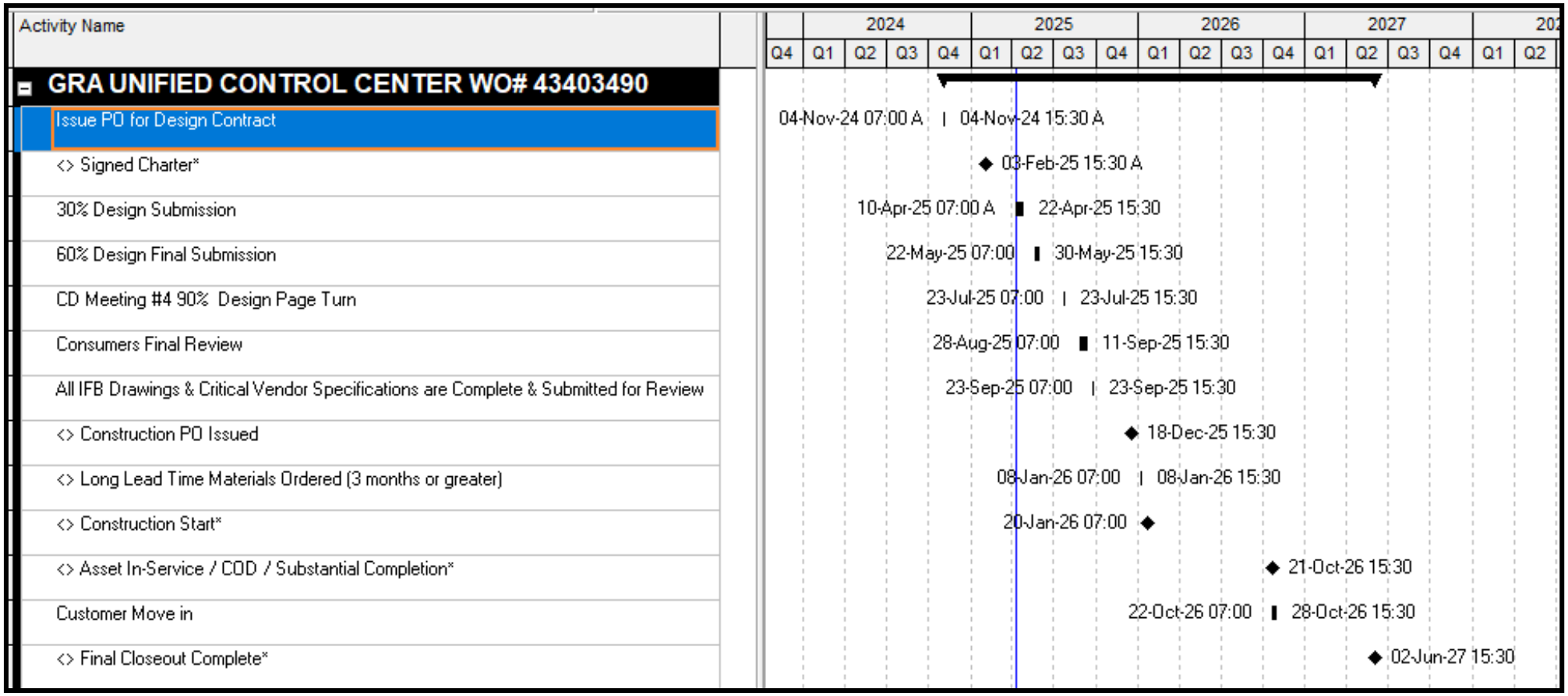
Consolidated / Control Dispatch Project

Consumers Energy
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CMS ENERGY

Consolidated / Control Dispatch Parnall – Project Schedule



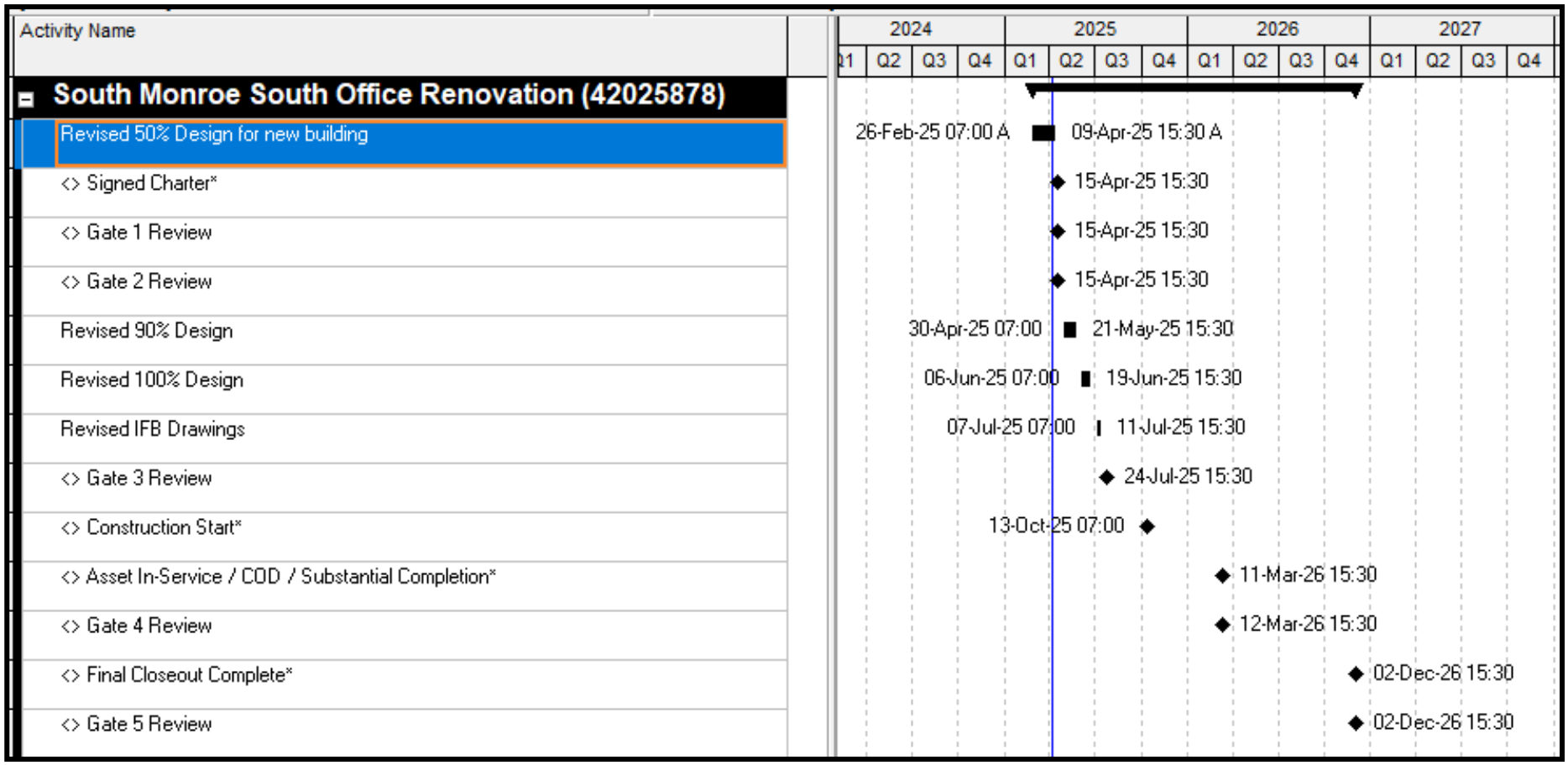
Consolidated / Control Dispatch Grand Rapids – Project Schedule



South Monroe Interior Renovation Project

Consumers Energy
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CMS ENERGY

South Monroe Interior Renovation – Project Schedule



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MEGAN L. HAYWARD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

CONSUMERS ENERGY
ELECTRIC ASSET MANAGEMENT

High Voltage Distribution(HVD) Pole Inspection Specifications

1. GENERAL SPECIFICATIONS

1.1. Consumers Energy shall provide all maps necessary for the wood pole inspection work to be performed.

1.2. The Contractor shall furnish all tools, equipment, inspection tags, bore tags, red tags and labor as required for the completion of wood pole inspection as prescribed in these specifications.

1.2.1. Each foreman employed by the Contractor working for Consumers Energy shall be a permanent, full-time employee of the Contractor. Each foreman shall have adequate training and not less than eight weeks experience as a Pole Inspection Foreman.

1.2.2. Each supervisor employed by the Contractor working for Consumers Energy shall be a permanent, full-time employee of the Contractor having not less than two years experience in supervising pole inspection crews.

1.2.3. The Contractor shall supply to a Consumers Energy representative written verification of the training and experience of each foreman and supervisor working for Consumers Energy before such work begins.

1.3. The Contractor shall inspect all poles with Consumers Energy facilities on them, which are connected electrically to the circuit or line section specified. All stub poles that are used for guying purposes should also be inspected. Poles within the protective fence of an electric substation shall also be inspected. Vacated or cut-off poles that had/have 3rd party attachments located adjacent to a Consumers Energy pole shall not be inspected, but the adjacent pole inspection record shall include yes or vacant value in the *PULL POLE* field.

1.3.1. For safety purposes, at least one individual per pole inspection team must attend substation entry training provided by Consumers Energy prior to entering a substation peremeter fence.

1.4. A representative of the Contractor shall be involved in a periodic conference call/meeting with Consumers Energy representatives to discuss inspection status and issues that may arise.

1.5. The Contractor shall electronically report the following information to Consumers Energy's representative each Monday by 12:00 noon (the format will be agreed upon with the Consumers Energy representative in advance):

1.5.1 Number of people who worked the previous week.

1.5.2 Specific days of week that each person worked during the previous week.

1.5.3 Specific circuit or line section that each crew worked during the previous week.

1.5.4 Planned circuit or line section of each crew for the current week.

1.6. The Contractor shall obtain, at their expense, all necessary permits required to complete the work prior to beginning the work requiring such permits.

1.7. Monthly the Contractor shall submit electronically via E-mail to a designated Consumers Energy's representative an invoice for the entire circuits or line sections that were completed. The Contractor shall include with each invoice a statement summarizing all work performed in each category of billing units.

1.8. The Contractor shall submit pole inspection data per individual circuit or line section, with the following conditions:

1.8.1. The data will be in Microsoft excel and either Microsoft Access format (MDB file) or ESRI Shapefile format.

1.8.2. CE Attachment B – Data Format lists the required data to capture for each pole inspection with a specific schema for Microsoft excel and either Microsoft Access format or ESRI Shapefile format.

1.8.3. A template for Microsoft excel and either Microsoft Access MDB file or ESRI Shapefile format with the required specific schema will be provided.

1.8.4. Transfer of circuit or line section data, including photos, Microsoft excel file and Microsoft Access database file or ESRI Shapefile will be packaged as one zip file named with the name and number of the Line Section or Feeder ID. The zip file will be transferred using FTP (File Transfer Protocol).

1.8.5. A sample set of twenty-five (25) pole data records fulfilling all data requirements specified in CE Attachment B – Data Format are to be submitted two weeks before start of pole inspections for testing and validation purposes.

1.9. The Contractor will specify and follow their quality assurance and audit process. The Contractor will work with Consumers Energy on an agreed upon acceptance process to ensure inspection and data quality requirements are achieved.

1.10. All work, including obtaining, recording, and reporting of the inspection data shall be entirely satisfactory to Consumers Energy and shall be subject to inspection by and approval of Consumers Energy. Any work submitted needing correction may be rejected and/or may delay payment. Common data errors need to be identified and corrected before data is submitted.

1.11. Consumers Energy may request a sample data set of an incomplete inspected circuit or line section for auditing purposes.

1.12. Contractor shall return any items/materials received from Consumers Energy and not used for inspection purposes.

2. VISUAL INSPECTION & GPS LOCATION SPECIFICATIONS

2.1. The Contractor will perform a visual pole inspection of the applicable poles on each circuit or line section assigned and record data per 1.8 above.

2.2. The Contractor shall report any system threatening or safety concerns promptly to the designated Consumers Energy representative(s). This includes but is not limited to:

1) A pole that the contractor determines to be an immediate replacement.
2) Any hazard that the contractor determines is a threat to public safety.
3) A floating phase or neutral wire.
4) A broken or severely cracked crossarm.

2.2.1 The Contractor could be requested by a Consumers Energy representative to stay on site until relieved by Consumers Energy representative. Consumers Energy will reimburse Contractor for time spent on site at agreed upon time and material rate.

2.2.2 A follow up E-mail shall be sent to a designated Consumers Energy representative for said pole or hazard within 3 days of call-in. A report template will be provided.

2.3. The Contractor will install a Consumers Energy pole number tag placed immediately above the inspection tag (if present), if a legible existing Consumers Energy pole number tag is not already present.

2.3.1. The Consumers Energy pole number tag is a numbered circular metal tag that will be provided by Consumers Energy.

2.3.2. The existing or new pole tag number will be recorded at each pole location.

2.4. The Contractor will obtain GPS location data accurate to 2-5 meters or better for each inspected pole. GPS location data will be recorded using the WGS84 (UTM) Coordinate System as a standard. See CE Attachment B – Data Format for electronic data reporting format.

2.5. The Contractor will take one in focus picture of the inspected pole. Picture should contain in its frame all the attachments on that pole.

2.5.1. Photos shall be captured with a device capable of 5.0 megapixels or greater.

2.5.2. The image file name will contain the tag number of the pole, followed by the compass heading of the direction the camera was facing when the photo was taken. The compass heading should be specified as the four cardinal directions and the four ordinal directions (N,NE,E,SE,S,SW,W,NW)

2.5.3. Image file must be in JPEG (.jpg) format.

2.5.4. For poles that are part of a muti-pole structure, photo shall include all poles of that structure.

3. POLE TEST INSPECTION SPECIFICATIONS

3.1. Consumer Energy’s prefered pole test inspection method is a device assisted test that helps identify poor pole conditions and voids.

3.2. The Contractor shall conduct a pole test inspection of all poles eleven (11) years old or older and which have not been inspected within the last five (5) years.

3.3. Designated poles shall be tested from ground line to 6 feet above ground line.

3.4. The Contractor shall install an agreed upon inspection tag at chest height on the road side of all tested poles.

3.5. The inspection tag shall have the name of the Contractor and the year of inspection stamped into the tag.

4. BORE TEST INSPECTION SPECIFICATIONS

4.1. The Contractor will perform a bore test on poles for the following reasons:

4.1.1. The pole test indicates the pole is decaying.

4.1.2. Visual decay is present.

4.1.3. Insects appear to be in the pole.

4.1.4. The pole has been backfilled or is discolored.

4.1.5. To satisfy a doubt about a pole's condition.

4.1.6. To determine the condition of a pole which was previously reinforced.

4.2. The Contractor shall only probe the pole surface if the pole has indication of defects from the visual or pole test inspections.

4.3. The Contractor shall follow the following bore test procedure:

4.3.1. Bore where either the pole test or visual inspection indicates the weakest point. Where two points are equally weak at the same level, bore the side of the pole perpendicular to the direction of the line.

4.3.2. If the pole test indicates decay or voids near ground, excavate to a depth of 6 to 8 inches and bore downward at a 45 degree angle. For poles installed in concrete or black top, bore downward at grade level at a 45 degree angle. (Read shell thickness on the 45 degree scale.) Poles with 1" shell thickness or less shall be indicated for replacement (Section 5.3).

4.3.3. For externally damaged sections, bore both the damaged side and 180 degrees from the damaged side.

4.3.4. For insect colonies, bore weakest point found during pole test.

4.3.5. Probe bored holes with depth gauge and record shell thickness. On all poles that are bored a shell thickness recorded in the appropriate data field is required. For poles where no void is found record a NV (No Void) in the *Bore* field. Record approximent height from ground line of minimum shell thickness in *Minimum Shell Thickness Height Field*.

4.3.6. Bore HVD candidate poles at 15" and 54" above the groundline to determine if it can be reinforced. (**Note**: "Candidate" poles are poles that qualify as replacement candidates per Section 5.1.2 Report the minimum shell thickness at 15" and 54" above the groundline. Report the pole as reinforceable if there is an average 2" of shell or greater at 15" above the groundline and an average 4" shell or greater at 54" above the groundline.

4.3.7. Plug all holes with 3" treated wood plugs.

4.3.8. Bore previously reinforced poles at the top of the steel truss. Identify previously reinforced pole as a replacement candidate if less than average 4" shell.

4.3.9. When inspection is complete replace any excavated soil, tamping it firmly around the pole butt. Make a small mound of soil to compensate for settling.

4.4. Inspect the pole for surface decay.

4.5. The Contractor will install an acceptable bore tag at chest height on the road side of all poles bore tested.

5. EVALUATION CRITERIA

5.1. The Contractor shall use the following bore test criteria to identify wood pole replacement candidates:

5.1.1 HVD Line Section Criteria

Original Circumference Just Above Groundline	Reduction of Circumference At or Below Groundline (Decayed Area)	Hollow Heart Minimum Allowable Thickness of Shell At Outer Decay Location	Pole Is A Replacement Candidate If Shell Thickness Is Less Than
35"	0"	2.0"	2.0"
	2"	2.0"	2.0"
	4.4"	Solid	Solid
	Greater than 4.4"	Candidate	-
40"	0"	2.0"	2.0"
	2"	2.0"	2.0"
	4"	2.6"	2.6"
	5.1"	Solid	Solid
	Greater than 5.1"	Candidate	-
50"	0"	2.0"	2.0"
	2"	2.2"	2.2"
	4"	2.8"	2.8"
	6.3"	Solid	Solid
	Greater than 6.3"	Candidate	-
60"	0"	2.3"	2.3"
	2"	2.6"	2.6"
	4"	3.1"	3.1"
	7.6"	Solid	Solid
	Greater than 7.6"	Candidate	-
70"	0"	2.7"	2.7"
	2"	3.0"	3.0"
	4"	3.4"	3.4"
	6"	4.0"	4.0"
	8"	5.4"	5.4"
	8.9"	Solid	Solid
	Greater than 8.9"	Candidate	-
80"	0"	3.0"	3.0"
	2"	3.4"	3.4"
	4"	3.8"	3.8"
	6"	4.3"	4.3"
	8"	5.2"	5.2"
	10.1"	Solid	Solid
	Greater than 10.1"	Candidate	-

5.2. Visual inspection can be used to identify rejected poles where there is severe decay at the top of the pole or where the pole is split or has large voids above chest height or other similar conditions. On all poles rejected due to visual inspection record reason in *Comments* field.

5.3. The Contractor shall install a red tag (white arrow) on all rejected poles at chest height on the road side of the pole, and indicate proper replacement value in the *ActionRequired* field.

5.3.1. Place the red tag "arrow up" if the pole was rejected from the visual inspection.

5.3.2. Place the red tag "arrow down" if the pole was rejected from the bore test inspection.

5.4. Replacement HVD candidate poles shall not be treated with wood preserving products unless the pole is reinforceable according to the criteria in 4.3.6.

6.0 Record Keeping

6.1 If the brand date is unreadable, estimate the manufactured year, height, and class of the pole and record as such.

6.2 Any poles that were unable to be inspected shall be recorded as follows:

- No in the *Accessible* field.
- Nearby GPS coordinate in GPS coordinate field.
- Additional location information in the *LocationDescription* field (ex. 200’ N of Pole# 1234567).
- A valid reason of why the pole is inaccessible in the *Comments* field (ex. Surrounded by water).

6.3 When testing multiple pole HVD structures, indicate which pole is being tested in the *HVD Structure Number* field. Example: #556N, #556S, #556W or #556E.

6.4 If the existing HVD pole is stubbed, indicate which pole is being tested in the HVD Structure Number field. Example: #556, #556stub.

6.5 If there is a guy pole attached to a HVD pole, indicate which pole is being tested in the HVD Structure Number field. Example: #556 (T pole), #556guy.

6.6 If there is a swamp fixture attached to the pole, indicate “swamp fixture” in the foundation type field.

6.7 A HVD pole with an air-break switch in single circuit lines may not have pole numbers on them; in such cases, use the switch number on the switch handle. Switches in double circuit lines should have pole numbers on them. Indicate the air-break switch number followed by “ABS” in the HVD Structure Number field. (ex. 177ABS)

6.8 For poles in substations, record “sub” in *HVD Structure Number* field for un-numbered substation poles.

7. HVD WOOD PRESERVATIVE TREATMENT SPECIFICATIONS

7.1. The Contractor will use only those wood preservative products listed on Attachment C for treating HVD wood poles.

7.2. The Contractor shall treat all HVD poles with groundline surface decay that reduces the original circumference of the pole by 2" or more.

7.3. The following method will be used to treat HVD poles with surface decay.

7.3.1. Excavate to a depth of 18".

7.3.2. Remove all external decay by chipping and wire brushing (avoid removing any good wood).

7.3.3. Remove all shavings and decayed material from the hole and surrounding area.

7.3.4. When possible, remove all attachments and replace when bandaging or preservative application is complete (never bandage over wire molding).

7.3.5. Apply bandage or preservative application so that it extends 3" above groundline. Cover the bandage or preservative with an approved moisture carrier.

7.3.6. Replace excavated soil and tamp. Do not place solid objects such as large rocks against the pole. Backfills shall be mounded around the pole to allow for settling.

7.3.7. No debris, loose soil, etc, is to be left in the pole area and shall be properly disposed of. Replace turf removed from excavation with care in its original location.

7.4. The contractor will treat all HVD poles with internal decay except replacement candidates which are not reinforceable. The contractor will treat all HVD poles infested with termite or ant colonies that are not replacement candidates or are reinforceable candidates. The contractor will internally treat all previously reinforced HVD poles with an average 4" shell or greater at 54" above groundline. The contractor shall treat all internally decayed HVD poles with an approved preservative, and in addition, decay voids/pockets shall be treated with pentachlorophenol or liquid copper napthenate.

7.4.1. The Contractor will follow the manufacturer's labeled directions for internal treatment of wood poles.

7.4.2. All holes will be plugged with 3" treated wood plugs following internal treatment.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Pole Inspection Plan by HVD Line

Electric Distribution

Case No.: U-21870
Exhibit No.: A-108 (MLH-2)
Page: 1 of 4
Witness: MLHayward
Date: June 2025

Line No.	(a) Line Name	(b) Number of Poles Inspected	(c) Number of Poles Failing Inspection	(d) Cost for Pole Replacements
1	RIFLE RIVER-GALLAGHER	15	2	$ 53,600
2	IONIA #2	77	8	$ 214,400
3	UPTON	30	3	$ 80,400
4	SOLVAY	63	7	$ 187,600
5	LEONI-BEECHER	1	0	$ -
6	HOMESTEAD	2	0	$ -
7	HOMESTEAD	142	15	$ 402,000
8	MANISTEE	6	1	$ 26,800
9	HOMESTEAD	74	8	$ 214,400
10	BIG RAPIDS	99	10	$ 268,000
11	GREENVILLE	28	3	$ 80,400
12	GREENVILLE	34	4	$ 107,200
13	GREENVILLE	22	2	$ 53,600
14	MASON	86	9	$ 241,200
15	BALZER	5	1	$ 26,800
16	BALZER	1	0	$ -
17	MASON	2	0	$ -
18	LESLIE	40	4	$ 107,200
19	LESLIE	125	13	$ 348,400
20	PARMA	216	23	$ 616,400
21	PARMA	256	27	$ 723,600
22	PARMA	48	5	$ 134,000
23	LESLIE	1	0	$ -
24	HARPER RD	35	4	$ 107,200
25	LESLIE	3	0	$ -
26	BALZER	180	19	$ 509,200
27	SQUIRES	14	1	$ 26,800
28	GRASS LAKE	25	3	$ 80,400
29	CHELSEA	10	1	$ 26,800
30	CHELSEA	3	0	$ -
31	STOCKBRIDGE	1	0	$ -
32	CHRYSLER	65	7	$ 187,600
33	GRASS LAKE	1	0	$ -
34	OKEMOS	145	15	$ 402,000
35	ROBERTS ST	32	3	$ 80,400
36	COLEMAN	68	7	$ 187,600
37	WIRTZ RD	8	1	$ 26,800
38	SANFORD	508	53	$ 1,420,400
39	CARSON CITY (DEJA - MIDDLETON)	235	25	$ 670,000
40	CARSON CITY (DEJA - MIDDLETON)	5	1	$ 26,800
41	HENRY	42	4	$ 107,200
42	HENRY	24	3	$ 80,400
43	SALZBURG	6	1	$ 26,800
44	SALZBURG	2	0	$ -
45	SALZBURG	2	0	$ -
46	COOPERSVILLE (FOUR MILE - ROCHESTER)	197	21	$ 562,800
47	GETTY	1	0	$ -
48	COOPERSVILLE (FOUR MILE - ROCHESTER)	3	0	$ -
49	EATON RAPIDS	53	6	$ 160,800
50	BURROWS (SALT ST - CLAREMONT)	100	10	$ 268,000
51	**Sub-Total**	**3141**	**330**	**$ 8,844,000**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pole Inspection Plan by HVD Line
Electric Distribution

Case No.: U-21870
Exhibit No.: A-108 (MLH-2)
Page: 2 of 4
Witness: MLHayward
Date: June 2025

Line No.	(a) Line Name	(b) Number of Poles Inspected	(c) Number of Poles Failing Inspection	(d) Cost for Pole Replacements
1	BURROWS (SALT ST - CLAREMONT)	34	4	$ 107,200
2	BURROWS (LAWNDALE - SALT ST)	159	17	$ 455,600
3	JANES	2	0	$ -
4	JANES	1	0	$ -
5	DORT - AC	107	11	$ 294,800
6	COURT #1	8	1	$ 26,800
7	COURT #1	39	4	$ 107,200
8	DORT - AC	37	4	$ 107,200
9	COURT #1	29	3	$ 80,400
10	JANES	125	13	$ 348,400
11	BAUM ST	67	7	$ 187,600
12	BAUM ST	18	2	$ 53,600
13	EAST GENESEE	7	1	$ 26,800
14	BAUM ST	25	3	$ 80,400
15	KNIGHT	140	15	$ 402,000
16	TRUMBULL	63	7	$ 187,600
17	TRUMBULL	55	6	$ 160,800
18	KNIGHT	1	0	$ -
19	TRUMBULL	2	0	$ -
20	KNIGHT	10	1	$ 26,800
21	WEALTHY - ELLSWORTH #2	4	0	$ -
22	TECUMSEH	5	1	$ 26,800
23	GERRISH	94	10	$ 268,000
24	GERRISH	113	12	$ 321,600
25	GERRISH	1	0	$ -
26	WGP	3	0	$ -
27	WGP	8	1	$ 26,800
28	HANOVER	10	1	$ 26,800
29	HANOVER	2	0	$ -
30	SUMMIT	84	9	$ 241,200
31	SUMMIT	19	2	$ 53,600
32	SUMMIT	3	0	$ -
33	SUMMIT	14	1	$ 26,800
34	HANOVER	8	1	$ 26,800
35	SUMMIT	1	0	$ -
36	KALARAMA - KILGORE TIE	2	0	$ -
37	ATWATER	1	0	$ -
38	BURDETT	3	0	$ -
39	MENDON	44	5	$ 134,000
40	ATWATER	116	12	$ 321,600
41	BURDETT	5	1	$ 26,800
42	BURDETT	7	1	$ 26,800
43	ATWATER	53	6	$ 160,800
44	KALARAMA	14	1	$ 26,800
45	KALARAMA	22	2	$ 53,600
46	PHILLIPS #1	25	3	$ 80,400
47	BREEDSVILLE	157	16	$ 428,800
48	GETTY	2	0	$ -
49	GETTY	20	2	$ 53,600
50	GETTY	89	9	$ 241,200
51	**Sub-Total**	**1858**	**195**	**$ 5,226,000**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pole Inspection Plan by HVD Line
Electric Distribution

Case No.: U-21870
Exhibit No.: A-108 (MLH-2)
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Witness: MLHayward
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Line No.	(a) Line Name	(b) Number of Poles Inspected	(c) Number of Poles Failing Inspection	(d) Cost for Pole Replacements
1	GETTY	77	8	$ 214,400
2	GETTY	31	3	$ 80,400
3	VERGENNES - MARQUETTE	10	1	$ 26,800
4	FLUSHING	41	4	$ 107,200
5	MONTROSE	236	25	$ 670,000
6	MONTROSE	55	6	$ 160,800
7	MONTROSE	2	0	$ -
8	OWOSSO	6	1	$ 26,800
9	FLUSHING	7	1	$ 26,800
10	MONTROSE	52	5	$ 134,000
11	MONTROSE	56	6	$ 160,800
12	OWOSSO	1	0	$ -
13	MANCHESTER	64	7	$ 187,600
14	MANCHESTER	13	1	$ 26,800
15	MANCHESTER	18	2	$ 53,600
16	MANCHESTER	1	0	$ -
17	LAMOREAUX	3	0	$ -
18	LAMOREAUX	32	3	$ 80,400
19	LAMOREAUX	1	0	$ -
20	PENTWATER	26	3	$ 80,400
21	KENT CITY	25	3	$ 80,400
22	CUMBERLAND	88	9	$ 241,200
23	DAVISON (DORT - IRISH ROAD)	82	9	$ 241,200
24	AC - DELANEY	38	4	$ 107,200
25	COURT #2	9	1	$ 26,800
26	OWOSSO	19	2	$ 53,600
27	OWOSSO	45	5	$ 134,000
28	OVID	1	0	$ -
29	GMI	68	7	$ 187,600
30	BEERS	49	5	$ 134,000
31	BALLENGER	41	4	$ 107,200
32	CALKINS	2	0	$ -
33	DIXIE	156	16	$ 428,800
34	CALKINS	28	3	$ 80,400
35	MILLER RD	1	0	$ -
36	CALKINS	15	2	$ 53,600
37	CALKINS	18	2	$ 53,600
38	BALLENGER	37	4	$ 107,200
39	ASYLUM	28	3	$ 80,400
40	CHEVROLET #4 (HEMPHILL - ALDRICH)	12	1	$ 26,800
41	CALKINS	9	1	$ 26,800
42	DIXIE	29	3	$ 80,400
43	GMI	8	1	$ 26,800
44	KAWKAWLIN	12	1	$ 26,800
45	HENRY	13	1	$ 26,800
46	STANDISH	1	0	$ -
47	STANDISH	410	43	$ 1,152,400
48	MERRILL	89	9	$ 241,200
49	SILICON	77	8	$ 214,400
50	CASCADE	1	0	$ -
51	**Sub-Total**	**2143**	**223**	**$ 5,976,400**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pole Inspection Plan by HVD Line
Electric Distribution

Case No.: U-21870
Exhibit No.: A-108 (MLH-2)
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Witness: MLHayward
Date: June 2025

Line No.	(a) Line Name	(b) Number of Poles Inspected	(c) Number of Poles Failing Inspection	(d) Cost for Pole Replacements
1	BRETON	4	0	$ -
2	CASCADE	104	11	$ 294,800
3	IONIA #2	86	9	$ 241,200
4	CASCADE	62	6	$ 160,800
5	THORNAPPLE	23	2	$ 53,600
6	THORNAPPLE	60	6	$ 160,800
7	HOWARD CITY	30	3	$ 80,400
8	LEE STREET	2	0	$ -
9	JOPPA	31	3	$ 80,400
10	MANCELONA	7	1	$ 26,800
28	**Sub-Total**	**409**	**41**	**$ 1,098,800**
29	**Total**	**7551**	**789**	**$ 21,145,200**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Bridge Period 16 Months Ending April 30th, 2026
($000)

Case No.: U-21870
Exhibit No.: A-109 (MLH-3)
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines Reliability	Maple City	3,354	7.2	Miles	Line Rebuilds	Customer*Minutes Avoided	251,854	Glen Arbor
2		Sonoma	501	0.7	Miles	Line Rebuilds	Customer*Minutes Avoided	6,808	Battle Creek
3		Plainwell	72	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	3,601	Plainwell
4		Greenville	72	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	1,403	Montcalm and Ionia Counties
5		Orleans	72	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	420	Montcalm and Ionia Counties
6		York	72	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	896	Montcalm and Ionia Counties
7		Cannonsburg	72	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	833	Montcalm and Ionia Counties
8		Allendale	159	0.2	Miles	Line Rebuilds	Customer*Minutes Avoided	1,748	Allendale
9		Bowen	462	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Grand Rapids
10		Bellevue	107	0.2	Miles	Line Rebuilds	Customer*Minutes Avoided	4,571	Calhoun and Eaton Counties
11		Golden	358	0.5	Miles	Line Rebuilds	Customer*Minutes Avoided	7,068	Bay and Midland Counties
12		Golden 2	503	0.3	Miles	Line Rebuilds	Customer*Minutes Avoided	4,241	Bay and Midland Counties
13		Golden 3	216	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	1,414	Bay and Midland Counties
14		Beals Rd - Hazelwood	87	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Allegan County
15		Niagara	40	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Saginaw
16		Greenville 2	1,287	1.8	Miles	Line Rebuilds	Customer*Minutes Avoided	40,406	Greenville
17		Golden 4	322	0.5	Miles	Line Rebuilds	Customer*Minutes Avoided	1,603	Midland
18		Hughes Rd	216	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	2,652	Calhoun County
19		Union City	1,004	1.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Calhoun County
20		Erie	5,414	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Monroe County
21		Union City 2	5,346	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Calhoun County
22		Nashville	7,579	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Barry County
23		Merrill	2,631	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Gration and Saginaw Counties
24		Grand Valley	2,174	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Kent County
25		Walker	1,201	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Kent County
26		Hodenpyl	2,231	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Wexford County
27		Wirtz Rd	3,062	-	Miles	Line Rebuilds	Benefit not realized until completion in 2026	-	Gladwin County
28		Middleville	166	5.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	124,887	Alto
29		Metro	132	2.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	128,710	Kent County
30		Metro 2	292	2.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	128,710	Kent County
31		Metro 3	636	2.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	148,017	Kent County
32		Bellevue	1,750	10.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	326,061	Calhoun and Eaton Counties
33		Bellevue 2	751	5.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	179,791	Calhoun and Eaton Counties
34		Westphalia	536	5.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	57,142	Pewamo
35		Westphalia 2	439	4.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	46,833	Westphalia
36		Westphalia 3	8	0.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	877	Westphalia
37		Athens	555	5.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	40,611	Athens
38		Manchester	82	0.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	36,304	Manchester
39		Oberlin	322	3.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	90,754	Oberlin
40		Oberlin 2	701	6.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	98,873	Oberlin
41		Oberlin 3	10	0.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	2,900	Oberlin
42		Carson City	31	0.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	10,721	Montcalm County
43		Carson City 2	843	0.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	-	Montcalm County
44		Mancelona	495	0.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	-	Antrim County
45		Mancelona 2	610	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2026	-	Kalkaska Cunty
46		Burr Oak	335	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2026	-	Burr Oak
47		Indian River	403	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2026	-	Indian River
48		Pole Replacements	54,856	2010	Poles	Pole Replacements	Customer*Minutes Avoided	2,572,172	Various locations statewide
49		Switch Replacements	7,364	51	Switches	Switch Replacements	Customer*Minutes Avoided	52,211	Various locations statewide
50		Pole Top Assembly Replacement	8,958	950	PTAs	Pole Top Assembly Replacements	Customer*Minutes Avoided	2,315,625	Various locations statewide
51		Line Sensors	2,111	168	Sensor Locations	Line Sensor Deployment	Improve reliability through increased outage detection		Various locations statewide
52		Real Estate	12,667			Right of Way Acquisition	Procure Right of Way needed to support projects		Various locations statewide
53		**HVD Lines Reliability Total**	**133,667**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
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For the Bridge Period 16 Months Ending April 30th, 2026
($000)

Case No.: U-21870
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Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Substations Reliability	WD0046 BULLOCK, REPL 3 BREAKERS *13*10	800	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Midland
2	HVD Substations Reliability	WD1068 WILLARD, REPL 3 BREAKERS *13*10	780	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Saginaw
3	HVD Substations Reliability	WD1448 PORT SHELDON, REPL BKR & SW *02	730	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Ottawa
4	HVD Substations Reliability	WD1090 SCOTT LK, REPL BRKRS & SWS *13	625	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Allegan
5	HVD Substations Reliability	WD0684 IOSCO, REPL 6 BKRS, 13 SWs *13	226	6	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	3,744	Iosco
6	HVD Substations Reliability	WD0235 BEALS ROAD, REPL FAILING OCB *10	20	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Kent
7	HVD Substations Reliability	WD0765 LOVELL, REPL FAILING BRKRS *02	590	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Kalamazoo
8	HVD Substations Reliability	WD1242 BRETON, REPL 5 OCBs *13	1200	5	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	3,120	Kent
9	HVD Substations Reliability	WD0727 BURLINGAME SUB, REPL VSW *13	500	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Kent
10	HVD Substations Reliability	WD0605 WEXFORD-REPL 138B GCB BUSHING *09	35	1	Projects	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Wexford
11	HVD Substations Reliability	WD0596 FRAME PLANT - REPL 2 BRKRS *02	450	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Genesee
12	HVD Substations Reliability	WD0195 WEADOCK REPL 99 & 1099 BKRS *09	718	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Bay
13	HVD Substations Reliability	WD0992 MICOR REPL 156 SW *10	500	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Jackson
14	HVD Substations Reliability	WD0951 LOOKING GLASS REPL 156 SW *10	240	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Clinton
15	HVD Substations Reliability	WD0999 RICKERT REPL 156 SW *10	850	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Ionia
16	HVD Substations Reliability	WD0940 BARRY REPL BRKRS CSW SWS PTS *02	1900	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Barry
17	HVD Substations Reliability	WD0605 WEXFORD, REPL 256 VARMSTR *10	527	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Wexford
18	HVD Substations Reliability	WD0175 EAST GENESEE REPL 3 BRKRS	1150	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Saginaw
19	HVD Substations Reliability	WD 0958 LAYTON REPL 3 BRKRS	1163	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Saginaw
20	HVD Substations Reliability	WD0956 Deja Replace 4 Breakers	1550	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Montcalm
21	HVD Substations Reliability	WD0387 Dort Replace 3 Gas Breakers	900	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Genesee
22	HVD Substations Reliability	WD0152 CEMENT CITY REPL 156 SW *10	584	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Jackson
23	HVD Substations Reliability	WD1160 Vevay Replace 156 Varmaster VSW	675	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Ingham
24	HVD Substations Reliability	WD0959 Beveridge Replace 4 Gas Breakers	1,200	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Genesee
25	HVD Substations Reliability	WD1211 Bard Road Replace 156 Varmaster VSW	675	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Gladwin
26	HVD Substations Reliability	WD0387 Dort Replace 156 Varmaster VSW	550	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Genesee
27	HVD Substations Reliability	WD0589 Thornapple Replace 156 Varmaster VSW	900	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Kent
28	HVD Substations Reliability	WD1529 Grace Road Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Benzie
29	HVD Substations Reliability	WD1071 LOCKWOOD, REPL MOLONEY PTs*13	60	2	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	9,600	Saginaw
30	HVD Substations Reliability	WD1073 OGEMAW, REPL SPT *13	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Ogemaw
31	HVD Substations Reliability	WD1171 MILES ROAD, REPL SPT *13	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Charlevoix
32	HVD Substations Reliability	WD0585 CHASE REPL SPT *13	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Lake
33	HVD Substations Reliability	WD0412 SYLVAN, REPL 46Kv SPT *13	100	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Washtenaw
34	HVD Substations Reliability	WD1248 FARR RD REPL 3 PTS *13	250	3	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	14,400	Manistee
35	HVD Substations Reliability	WD0235 BEALS RD, YARD & GROUNDS *10	45	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Kent
36	HVD Substations Reliability	WD0755 DELTA COLLEGE INST MOBILE PAD *02	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Bay
37	HVD Substations Reliability	WD1523 SINCLAIR - REPL BAT & WRK SPC *02	200	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Kent
38	HVD Substations Reliability	WD0696 SUPPLY DEPOT REPL REG Y & X *04	200	2	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	2,400	Genesee
39	HVD Substations Reliability	WD0195 WEADOCK REPL CAP BANK #1 CONTROLLER *04	95	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Bay
40	HVD Substations Reliability	WD0400 Whiting Repl 2 Dewatering Pumps	255	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Monroe
41	HVD Substations Reliability	WD0725 BEGOLE GATE,WALKWAY, SURFACE *04	25	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Gratiot
42	HVD Substations Reliability	WD0958 LAYTON REPLACE GATES	95	2	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Saginaw
43	HVD Substations Reliability	WD0210 WEYERHAEUSER NEW GATE DRIVE *04	130	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Crawford
44	HVD Substations Reliability	WD0110 HASTINGS REPL 277 SPT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Barry
45	HVD Substations Reliability	WD0492 HASKELITE REPL NORM & ALT SPT	130	2	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	9,600	Kent
46	HVD Substations Reliability	WD2058 Disposal Plant REPL 2 PT	100	2	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	9,600	Saginaw
47	HVD Substations Reliability	WD1504 HORSESHOE CREEK REPL BATT *13-23	75	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Montcalm
48	HVD Substations Reliability	WD0131 Grey Iron TB3 & TB4 LTC controllers (WBS being updated)	84	2	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	9,600	Saginaw
49	HVD Substations Reliability	WD0332 BATAVIA REPLACE RTU/T1	225	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Branch
50	HVD Substations Reliability	WD0109 ELLSWORTH REPLACE RTU/T1	176	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Kent
51	HVD Substations Reliability	WD1504 HORSESHOE CREEK REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Montcalm
52	HVD Substations Reliability	WD1257 SIMPSON REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		St Joseph
53	HVD Substations Reliability	WD0555 PAGE AVR REPLACE BATT,RACK,CONT	75	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Jackson
54	HVD Substations Reliability	WD0951 LOOKING GLASS REPL BATTERY INTO NEW CCE	300	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ingham
55	HVD Substations Reliability	WD1349 CLEARWATER REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Kalkaska
56	HVD Substations Reliability	WD0892 MANLIUS REPLACE RTU/T1	165	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Allegan
57	HVD Substations Reliability	WD1068 Willard battery	235	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Saginaw
58	HVD Substations Reliability	WD0610 BINGHAM REPLACE RTU/T1	244	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Clinton
59	HVD Substations Reliability	WD0986 BRICKYARD REPLACE RTU/T1	203	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Muskegon
60	HVD Substations Reliability	WD1171 MILES ROAD REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Charlevoix
61	HVD Substations Reliability	WD0680 WHITE LAKE REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Muskegon
62	HVD Substations Reliability	WD0064 BEECHER REPLACE RTU/T1	212	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Lenawee
63	HVD Substations Reliability	WD1254 DOWLING REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Lenawee
64	HVD Substations Reliability	WD0500 BOARDMAN REPL BATTERY INTO NEW CCE	224	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Grand Traverse
65	HVD Substations Reliability	WD0152 CEMENT CITY REPL BATTERY INTO NEW CCE	223	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Jackson
66	HVD Substations Reliability	WD0725 BEGOLE REPL BATTERY	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Gratiot
67	HVD Substations Reliability	WD0785 Delaney Replace Battery	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Genesee
68	HVD Substations Reliability	WD0152 CEMENT CITY REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Jackson
69	HVD Substations Reliability	WD1219 COLE CREEK REPL BATTERY	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Genessee
70	HVD Substations Reliability	WD1071 Lockwood Prod Install Mobile, drive	120	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Saginaw
71	HVD Substations Reliability	WD0967 McNally Install Mobile Pad	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Charlevoix
72	HVD Substations Reliability	WD0573 Ohman Road Install Mobile Pad	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Osceola
73	HVD Substations Reliability	WD0053 Lenawee Stamping Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Lenawee
74	HVD Substations Reliability	WD0095 CROTON REPLACE RTU/T1	315	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Newaygo
75	HVD Substations Reliability	WD1123 FELCH ROAD REPLACE RTU/T1	357	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Newaygo
76	HVD Substations Reliability	WD1214 GLEANER REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Saginaw
77	HVD Substations Reliability	WD0400 WHITING REPLACE RTU/T1	357	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Monroe
78	HVD Substations Reliability	WD0123 GROUT REPL BATTERY INTO NEW CCE	300	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Gladwin
79	HVD Substations Reliability	WD0433 FOUR MILE REPL BATTERY	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Kent
80	HVD Substations Reliability	WD0600 Cornell Replace Battery	300	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Shiawassee
81	HVD Substations Reliability	WD0738 Pipe Line Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Bay
82	HVD Substations Reliability	WD0384 Jackson RCP Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Jackson
83	HVD Substations Reliability	WD0799 Sealed Power Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Muskegon
84	HVD Substations Reliability	WD1445 Big Chief Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Bay
85	HVD Substations Reliability	WD1243 Amway Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Kent
86	HVD Substations Reliability	WD0837 Briggs & Stratton Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Muskegon
87	HVD Substations Reliability	WD0161 Rochester Products Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ottawa
88	HVD Substations Reliability	WD0586 Leith Street Replace Moloney PTs	130	2	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	9,600	Genesee
89	HVD Substations Reliability	WD0362 Washington Replace Moloney SPT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Mason
90	HVD Substations Reliability	WD0116 Hurley Replace Moloney PT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Genesee
91	HVD Substations Reliability	WD0360 Liberty Moloney PT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Calhoun
92	HVD Substations Reliability	WD1214 Gleaner Replace Moloney SPT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Saginaw
93	HVD Substations Reliability	WD0074 Hudson Replace Moloney SPT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Lenawee
94	HVD Substations Reliability	WD0980 Spaulding Replace Moloney PT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Kent
95	HVD Substations Reliability	WD1180 Wolverine Replace Moloney PT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Calhoun
96	HVD Substations Reliability	WD1167 West Shore Yard Improvements (fence, stone, gate)	300	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Mason
97	HVD Substations Reliability	WD0332 Batavia Animal Mit, Security Improvement, Fence replacements	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Branch
98	HVD Substations Reliability	WD0235 Beals Animal Mit, Security Improvement, Fence replacements (hig	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47034	Kent
99	HVD Substations Reliability	WD0940 Barry Animal Mit, Security Improvement, Fence replacements, Roc	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47034	Barry
100	HVD Substations Reliability	WD0240 Cobb Animal Mit, Security Improvement, Fence replacements	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47034	Muskegon
101	HVD Substations Reliability	WD1099 Raisin Animal Mit, Security Improvement, Fence replacements	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Lenawee
102	HVD Substations Reliability	WD0837 Briggs & Straton Animal Mit, Security Improvement, Fence replace	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Muskegon
103	HVD Substations Reliability	WD1220 Bass Creek, Security Improvement, Fence replacement	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ottawa
104	HVD Substations Reliability	WD0021 Rogers Heights, Security Improvement, Fence replacement	300	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Mecosta
105	HVD Substations Reliability	WD1169 Mecosta Yard Improvement	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Mecosta
106	HVD Substations Reliability	WD0095 Croton, Security Improvement, Fence replacement, lighting	750	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Newaygo
107	HVD Substations Reliability	WD0560 Riverview yard lighting improvements	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Kalamazoo
108	HVD Substations Reliability	WD0235 Beals Road Station Power upgrades	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Kent
109	HVD Substations Reliability	WD0999 Rickert Replace Battery	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ionia
110	HVD Substations Reliability	WD0095 Croton Control House Improvement	664	2	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Newaygo
111	HVD Substations Reliability	WD1259 David Replace Transformer #1 Monitor	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Ionia
112	HVD Substations Reliability	WD1492 Sonoma Replace Transformer #1 Monitor	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Calhoun
113	HVD Substations Reliability	WD1249 Algoma Replace Obsolete #1 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Kent
114	HVD Substations Reliability	WD1220 Bass Creek Replace Obsolete #1 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Ottawa
115	HVD Substations Reliability	WD1123 Felch Road Replace Obsolete #1 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Newaygo
116	HVD Substations Reliability	WD0433 Four Mile Replace Obsolete #2 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Kent
117	HVD Substations Reliability	WD0980 Spaulding Replace Obsolete #1 & #2 Cap Bank Controllers	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Kent
118	HVD Substations Reliability	WD0402 Replace Obsolete #1 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Allegan
119	HVD Substations Reliability	WD1108 Williams Replace Obsolete #1 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Allegan
120	HVD Substations Reliability	Batteries Identified during testing	1000	4	projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
121	HVD Substations Reliability	Yard/Animal improvement (HVD or SEC)	2033	8	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	376,272	Various
122	HVD Substations Reliability	Cap bank controlers	800	16	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Various
123	HVD Substations Reliability	Ladder Remediation	2000	40	projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
124	HVD Substations Reliability	WD0507 DETROIT GASKET 46kV MOAB SCADA*13	30	2	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	40,950	Ionia
125	HVD Substations Reliability	WD0235 BEALS RD, REPL 14 SWs *13	160	14	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	286,650	Kent
126	HVD Substations Reliability	WD0151 DELHI, REILBLTY REPL 17 SWs *13	900	17	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	348,075	Ingham
127	HVD Substations Reliability	WD1090 SCOTT LAKE, REPL SW & POLE *09	60	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Allegan
128	HVD Substations Reliability	WD1177 Rust Park 3 switches	140	3	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	61,425	Saginaw
129	HVD Substations Reliability	WD1108 WILLIAMS - REPL 156 SW *09	463	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Allegan
130	HVD Substations Reliability	WD0956 Deja Repl 14S, 1175, 1185 SWs	279	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Montcalm
131	HVD Substations Reliability	WD0170 HARVEY ST REPL 108S SWS *09	60	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Kent
132	HVD Substations Reliability	WD0951 LOOKING GLASS REPL 3 SWS *09	150	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Clinton
133	HVD Substations Reliability	WD1477 CHURCHILL REPL 2 SWITCHES *04	180	2	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	40,950	Ingham
134	HVD Substations Reliability	WD0364 Iron Street Replace 2 MOABS	300	2	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	40,950	Genesee
135	HVD Substations Reliability	WD0083 BLACKSTONE REPL 127S SW	100	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Jackson
136	HVD Substations Reliability	WD0946 NEWARK, REPL TYPE U BSHNG *13	140	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Oakland
137	HVD Substations Reliability	WD1529 GRACE RD, REPL TPE U BSHNG *13	300	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	30	Benzie
138	HVD Substations Reliability	WD0573 OHMAN RD REPL O+C BSHNGS *13	140	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Osceola
139	HVD Substations Reliability	WD0231 Mendon TB2 bushings	90	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	St Joseph
140	HVD Substations Reliability	WD0090 CHARLOTTE, REPL HS BSHNGS*13	300	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Eaton
141	HVD Substations Reliability	WD0410 Flushing Repl Bushing & Fans	30	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Genesee
142	HVD Substations Reliability	WD0944 Certainteed Repl TB1 Bushings	55	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	30	Jackson
143	HVD Substations Reliability	WD0194 Lake Lansing Repl HS Bushings	60	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Ingham
144	HVD Substations Reliability	WD1095 Dunham TB1 bushings & arresters	70	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Genesee
145	HVD Substations Reliability	Emergent Equipment replacements (Bushings, arrestors, Switches)	1000	8	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	556,416	Various
145		**HVD Substations Reliability Total:**	**47,322**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Bridge Period 16 Months Ending April 30th, 2026
($000)

Case No.: U-21870
Exhibit No.: A-109 (MLH-3)
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Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	Transformer Bank Replacements and Substati	WD0270 N BELDING SUB REBUILD *10	1,742	1	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Ionia
2	Transformer Bank Replacements and Substati	WD0354 ALMA PRODUCTS RPL TB1 *10	1,700	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Gratiot
3	Transformer Bank Replacements and Substati	WD0596 FRAME PLANT - REPL TB2 & TB3 *02	1,869	2	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	2	Genesee
4	Transformer Bank Replacements and Substati	WD0670 STOVER REPL TB1 *10	2,000	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Antrim
5	Transformer Bank Replacements and Substati	WD1109 WACKERLY REPLACE TB NO.1 *10	2,494	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Midland
6	Transformer Bank Replacements and Substati	WD1323 ORCHARD ROAD RPL TB1 & TB2 *10	2,799	2	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	14,040	Midland
7	Transformer Bank Replacements and Substati	WD1396 STEERING GEAR TB#1,2,3 FLRS *10	1,300	3	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	4	Saginaw
8	Transformer Bank Replacements and Substati	WD1435 BORGESS REPL TB 1, TB2 *13*04	3,211	2	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	2	Kalamazoo
9	Transformer Bank Replacements and Substati	WD1722 BUSKIRK NEW 138/46 KV BULK SUB*13	6,800	1	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Allegan
10	Transformer Bank Replacements and Substati	Alma Substations Rebuild (Armory)	4,000	1	Projects	HVD Substation Rebuilds	Benefit not realized until completion	-	Gratiot
11	Transformer Bank Replacements and Substati	Blackstone Substation Rebuild	5,287	1	Projects	HVD Substation Rebuilds	Benefit not realized until completion	-	Jackson
12	Transformer Bank Replacements and Substati	WD0755 DELTA COLLEGE RPL TB *02	1,350	2	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	2	Bay
13	Transformer Bank Replacements and Substati	WD0755 DELTA COLLEGE INST MOBILE PAD *02	270	1	Projects	HVD Substation Transformer Replacement Imminent Failure	System Operability	0	Bay
14	Transformer Bank Replacements and Substati	Progress Payments for TRF	11844	30	Equipment	Major material procurement			Various
15		**Transformer Bank Replacements and Substation RebuildsTotal:**	46,666						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2024-2025 Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-109 (MLH-3)
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Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Substations Reliability	ANGELL	696	1	Project	New or Rebuild Substations	Acme Twp, Grand Traverse Co.	Reliability - outage minutes avoided	493,560
2		BUCKEYE	2,650	1	Project	New or Rebuild Substations	Buckeye Twp, Gladwin Co.	Reliability - outage minutes avoided	130,596
3		COLEMAN	206	1	Project	New or Rebuild Substations	Warren Twp, Midland Co.	Reliability - outage minutes avoided	297,480
4		EAST TAWAS	2,300	1	Project	New or Rebuild Substations	Baldwin Twp, Iosco Co.	Reliability - outage minutes avoided	4,074,840
5		EDGEWOOD	1,700	1	Project	New or Rebuild Substations	Lafayette Twp, Gratiot Co.	Reliability - outage minutes avoided	570,240
6		HARMON ROAD	695	1	Project	New or Rebuild Substations	Woodbridge Twp, Hillsdale Co.	Reliability - outage minutes avoided	1,749,600
7		HOUGHTON LAKE	14,259	1	Project	New or Rebuild Substations	Roscommon Twp, Roscommon Co.	Reliability - outage minutes avoided	6,099,840
8		IARGO	600	1	Project	New or Rebuild Substations	Oscoda Twp, Iosco Co.	Reliability - outage minutes avoided	223,560
9		LOWER LAKE	75	1	Project	New or Rebuild Substations	Hastings Twp, Barry Co.	Reliability - outage minutes avoided	1,348,920
10		MCKEIGHAN	330	1	Project	New or Rebuild Substations	Chesaning Twp, Saginaw Co.	Reliability - outage minutes avoided	1,345,680
11		MONUMENT	495	1	Project	New or Rebuild Substations	Oscoda Twp, Iosco Co.	Reliability - outage minutes avoided	456,840
12		NORTH ADAMS	1,300	1	Project	New or Rebuild Substations	Adams Twp, Hillsdale Co.	Reliability - outage minutes avoided	144,120
13		PRESCOTT	1,235	1	Project	New or Rebuild Substations	Richland Twp, Ogemaw Co.	Reliability - outage minutes avoided	1,401,840
14		PULLMAN	665	1	Project	New or Rebuild Substations	Lee Twp, Allegan Co.	Reliability - outage minutes avoided	1,994,760
15		REA ROAD	300	1	Project	New or Rebuild Substations	Au Sable Twp, Iosco Co.	Reliability - outage minutes avoided	370,440
16		WALDRON	30	1	Project	New or Rebuild Substations	Wright Twp, Hillsdale Co.	Reliability - outage minutes avoided	1,050,840
17		WESTPHALIA	665	1	Project	New or Rebuild Substations	Westphalia Twp, Clinton Co.	Reliability - outage minutes avoided	1,126,440
18		MOBILE 15	420	1	Project	Mobile Substations	Statewide	Reliability - outage minutes avoided	-
19		MOBILE 26	1,465	1	Project	Mobile Substations	Statewide	Reliability - outage minutes avoided	-
20		MOBILE 29	1,465	1	Project	Mobile Substations	Statewide	Reliability - outage minutes avoided	-
21		BEAVER	100	1	Project	Animal Mitigation	Beaver Twp, Bay Co.	Reliability - outage minutes avoided	195,120
22		CAMDEN	100	1	Project	Animal Mitigation	Camden Twp, Hillsdale Co.	Reliability - outage minutes avoided	156,600
23		FREEPORT	100	1	Project	Animal Mitigation	Irving Twp, Barry Co.	Reliability - outage minutes avoided	159,720
24		GREENBUSH	100	1	Project	Animal Mitigation	Harrisville Twp, Alcona Co.	Reliability - outage minutes avoided	226,800
25		LAKE SHORE	80	1	Project	Animal Mitigation	Grand Haven Twp, Ottawa Co.	Reliability - outage minutes avoided	120
26		MARKET AVENUE	100	1	Project	Animal Mitigation	Walker Twp, Kent Co.	Reliability - outage minutes avoided	120
27		MICOR	120	1	Project	Animal Mitigation	Summit Twp, Jackson Co.	Summit Twp, Jackson Co.	79,440
28		MUSKEGON TREATMENT	100	1	Project	Animal Mitigation	City of Muskegon, Muskegon Co.	Reliability - outage minutes avoided	120
29		SPRINGFIELD	100	1	Project	Animal Mitigation	Battle Creek Twp, Calhoun Co.	Reliability - outage minutes avoided	369,360
30		TWIN LAKE	120	1	Project	Animal Mitigation	Dalton Twp, Muskegon Co.	Reliability - outage minutes avoided	254,160
31		VENTURA	120	1	Project	Animal Mitigation	Park Twp, Ottawa Co.	Reliability - outage minutes avoided	120
32		WHITE ROAD	100	1	Project	Animal Mitigation	Egelston Twp, Muskegon Co.	Reliability - outage minutes avoided	120
33		WURTSMITH	132	1	Project	Animal Mitigation	Oscoda Twp, Iosco Co.	Reliability - outage minutes avoided	213,600
34		BREEDSVILLE	300	4	Regulators	Regulator Replacements	Columbia Twp, Van Buren Co.	Service Quality; number of customers	2,471
35		BEALS ROAD TB2-1	702	1	Project	Transformer Replacements	Wyoming Twp, Kent Co.	Reliability - outage minutes avoided	283,500
36		BEALS ROAD TB2-2	702	1	Project	Transformer Replacements	Wyoming Twp, Kent Co.	Reliability - outage minutes avoided	427,860
37		BELKNAP	957	1	Project	Transformer Replacements	Ganges Twp, Allegan Co.	Reliability - outage minutes avoided	570,240
38		BROADMOOR TB3	1,848	1	Project	Transformer Replacements	Paris Twp, Kent Co.	Reliability - outage minutes avoided	386,460
39		BROADMOOR TB4	1,848	1	Project	Transformer Replacements	Paris Twp, Kent Co.	Reliability - outage minutes avoided	421,560
40		LAGRAVE	971	1	Project	Transformer Replacements	City of Grand Rapids, Kent Co.	Reliability - outage minutes avoided	25,380
41		LITCHFIELD	949	1	Project	Transformer Replacements	Litchfield Twp, Hillsdale Co.	Reliability - outage minutes avoided	1,530,360
42		NORTHPORT	908	1	Project	Transformer Replacements	Leelanau Twp, Leelanau Co.	Reliability - outage minutes avoided	330,120
43		SARANAC	993	1	Project	Transformer Replacements	Boston Twp, Ionia Co.	Reliability - outage minutes avoided	267,120
44		ALABAMA	134	1	Project	DSCADA Projects	Bridgeport Twp, Saginaw Co.	Reliability - outage minutes avoided	241,560
45		BIRCH RUN	825	1	Project	DSCADA Projects	Birch Run Twp, Saginaw Co.	Reliability - outage minutes avoided	157,800
46		CALKINS	513	1	Project	DSCADA Projects	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	463,320
47		EDDY	232	1	Project	DSCADA Projects	Buena Vista Twp, Saginaw Co.	Reliability - outage minutes avoided	74,520
48		ENSLEY	625	1	Project	DSCADA Projects	Ensley Twp, Newaygo Co.	Reliability - outage minutes avoided	175,560
49		GERRISH TB1	200	1	Project	DSCADA Projects	Gerrish Twp, Roscommon Co.	Reliability - outage minutes avoided	230,520
50		GERRISH TB2	448	1	Project	DSCADA Projects	Gerrish Twp, Roscommon Co.	Reliability - outage minutes avoided	159,840
51		LIBERTY	74	1	Project	DSCADA Projects	Battle Creek Twp, Calhoun Co.	Reliability - outage minutes avoided	211,800
52		MCGRAW	438	1	Project	DSCADA Projects	Portsmouth Twp, Bay Co.	Reliability - outage minutes avoided	163,200
53		MCKEIGHAN	125	1	Project	DSCADA Projects	Chesaning Twp, Saginaw Co.	Reliability - outage minutes avoided	149,520
54		NORTHERN FIBRE	248	1	Project	DSCADA Projects	Olive Twp, Ottawa Co.	Reliability - outage minutes avoided	156,120
55		ROUND LAKE	502	1	Project	DSCADA Projects	Woodstock Twp, Leenawee Co.	Reliability - outage minutes avoided	122,040
56		SOUTH WASHINGTON AVE	396	1	Project	DSCADA Projects	Buena Vista Twp, Saginaw Co.	Reliability - outage minutes avoided	143,640
57		SPRINGFIELD	244	1	Project	DSCADA Projects	Battle Creek Twp, Calhoun Co.	Reliability - outage minutes avoided	369,360
58		SWARTZ CREEK	400	1	Project	DSCADA Projects	Gaines Twp, Genesee Co.	Reliability - outage minutes avoided	476,880
59		**LVD Substations Reliability Total**	**48,504**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2024-2025 Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
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Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Substations Rehabilitation	BALLENGER	468	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	5,321,160
2		BELLAIRE	1,073	1	Project	Allis Chalmers Substation Transformers	Kearney Twp, Antrim Co.	Reliability - outage minutes avoided	1,192,320
3		CONKLIN PARK	660	1	Project	Allis Chalmers Substation Transformers	Croton Twp, Newaygo Co.	Reliability - outage minutes avoided	1,896,480
4		COOPER	255	1	Project	Allis Chalmers Substation Transformers	Cooper Twp, Kalamazoo Co.	Reliability - outage minutes avoided	1,897,560
5		CROFTON	1,155	1	Project	Allis Chalmers Substation Transformers	Kalkaska Twp, Kalkaska Co.	Reliability - outage minutes avoided	5,400
6		DIXIE	1,980	1	Project	Allis Chalmers Substation Transformers	Mt Morris Twp, Genesee Co.	Reliability - outage minutes avoided	3,402,000
7		FOUNTAIN	255	1	Project	Allis Chalmers Substation Transformers	Battle Creek Twp, Calhoun Co.	Reliability - outage minutes avoided	736,560
8		GLADWIN	468	1	Project	Allis Chalmers Substation Transformers	Grout Twp, Gladwin Co.	Reliability - outage minutes avoided	3,852,360
9		GMI	511	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	2,160
10		GODFREY	869	1	Project	Allis Chalmers Substation Transformers	Vergennes Twp, Kent Co.	Reliability - outage minutes avoided	1,273,320
11		GOLDEN	468	1	Project	Allis Chalmers Substation Transformers	Midland Twp, Midland Co.	Reliability - outage minutes avoided	1,510,920
12		HALLS LAKE	651	1	Project	Allis Chalmers Substation Transformers	Sheridan Twp, Calhoun Co.	Reliability - outage minutes avoided	46,620
13		HART	100	1	Project	Allis Chalmers Substation Transformers	Hart Twp, Oceana Co.	Reliability - outage minutes avoided	464,400
14		INGHAM	1,980	1	Project	Allis Chalmers Substation Transformers	City of Jackson, Jackson Co.	Reliability - outage minutes avoided	2,008,800
15		KINGSLEY	1,238	1	Project	Allis Chalmers Substation Transformers	Paradise Twp, Grand Traverse Co.	Reliability - outage minutes avoided	3,201,120
16		LEITH STREET	2,310	1	Project	Allis Chalmers Substation Transformers	City of Flint, Genesee Co.	Reliability - outage minutes avoided	740,520
17		LENNON ROAD	409	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	474,660
18		LIBERTY	1,320	1	Project	Allis Chalmers Substation Transformers	Battle Creek Twp, Calhoun Co.	Reliability - outage minutes avoided	317,700
19		LYONS	333	1	Project	Allis Chalmers Substation Transformers	Lyons Twp, Ionia Co.	Reliability - outage minutes avoided	1,314,360
20		MAYFAIR	409	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	2,847,960
21		MERSON	990	1	Project	Allis Chalmers Substation Transformers	Trowbridge Twp, Allegan Co.	Reliability - outage minutes avoided	2,272,320
22		NESTROM	428	1	Project	Allis Chalmers Substation Transformers	Fruitland Twp, Muskegon Co.	Reliability - outage minutes avoided	2,444,040
23		NEWBURG	990	1	Project	Allis Chalmers Substation Transformers	Shiawassee Twp, Shiawassee Co.	Reliability - outage minutes avoided	2,220,480
24		OTTAWA BEACH	292	1	Project	Allis Chalmers Substation Transformers	Park Twp, Ottawa Co.	Reliability - outage minutes avoided	2,938,680
25		STANTON	2,029	1	Project	Allis Chalmers Substation Transformers	Evergreen Twp, Montcalm Co.	Reliability - outage minutes avoided	1,036,800
26		WILSON	825	1	Project	Allis Chalmers Substation Transformers	Walker Twp, Kent Co.	Reliability - outage minutes avoided	1,080
27		BAGLEY	150	1	Project	Equipment Replacement and Regulatory	Bagley Twp, Otsego Co.	Regulatory Compliance	-
28		BLUE WATER	198	1	Project	Equipment Replacement and Regulatory	Bingham Twp, Clinton Co.	Reliability - outage minutes avoided	566,100
29		BROADWAY	248	1	Project	Equipment Replacement and Regulatory	Fruitport Twp, Muskegon Co.	Reliability - outage minutes avoided	526,320
30		DUTTON	1,393	1	Project	Equipment Replacement and Regulatory	Gaines Twp, Kent Co.	Reliability - outage minutes avoided	970,740
31		EAST PARIS	200	1	Project	Equipment Replacement and Regulatory	Paris Twp, Kent Co.	Regulatory Compliance	-
32		FAIRBANKS	1,165	1	Project	Equipment Replacement and Regulatory	City Of Grand Rapids, Kent Co.	Reliability - outage minutes avoided	123,120
33		GILSON	1,250	1	Project	Equipment Replacement and Regulatory	Home Twp, Montcalm Co.	Regulatory Compliance	-
34		HAGER PARK	1,140	1	Project	Equipment Replacement and Regulatory	Georgetown Twp, Ottawa Co.	Regulatory Compliance	-
35		HASKELITE	248	1	Project	Equipment Replacement and Regulatory	Walker Twp, Kent Co.	Regulatory Compliance	-
36		HOWARD CITY	1,034	1	Project	Equipment Replacement and Regulatory	Reynolds Twp, Montcalm Co.	Reliability - outage minutes avoided	239,400
37		HUDSONVILLE	1,393	1	Project	Equipment Replacement and Regulatory	Georgetown Twp, Ottawa Co.	Reliability - outage minutes avoided	739,620
38		KIPP ROAD	371	1	Project	Equipment Replacement and Regulatory	Vevay Twp, Ingham Co.	Regulatory Compliance	-
39		LAGRAVE	600	1	Project	Equipment Replacement and Regulatory	City Of Grand Rapids, Kent Co.	Reliability - outage minutes avoided	104,580
40		LAKE CITY	330	1	Project	Equipment Replacement and Regulatory	Reeder Twp, Missaukee Co.	Regulatory Compliance	-
41		LAKE SHORE	724	1	Project	Equipment Replacement and Regulatory	Grand Haven Twp, Ottawa Co.	Reliability - outage minutes avoided	180
42		LETTS ROAD	1,485	1	Project	Equipment Replacement and Regulatory	Larkin Twp, Midland Co.	Regulatory Compliance	-
43		MANCELONA	910	1	Project	Equipment Replacement and Regulatory	Mancelona Twp, Antrim Co.	Reliability - outage minutes avoided	2,010,960
44		NEFF ROAD	495	1	Project	Equipment Replacement and Regulatory	Vienna Twp, Genesee Co.	Reliability - outage minutes avoided	576,540
45		NEW RICHMOND	409	1	Project	Equipment Replacement and Regulatory	Manlius Twp, Allegan Co.	Reliability - outage minutes avoided	719,280
46		NINETEEN MILE	1,761	1	Project	Equipment Replacement and Regulatory	Green Twp, Mecosta Co.	Regulatory Compliance	-
47		NORTHERN FIBRE	600	1	Project	Equipment Replacement and Regulatory	Olive Twp, Ottawa Co.	Regulatory Compliance	-
48		PORT CALCITE	1,106	1	Project	Equipment Replacement and Regulatory	Rogers Twp, Presque Isle Co.	Reliability - outage minutes avoided	2,147,040
49		RIVERTOWN	165	1	Project	Equipment Replacement and Regulatory	Wyoming Twp, Kent Co.	Regulatory Compliance	-
50		RUST PARK	149	1	Project	Equipment Replacement and Regulatory	City of Saginaw, Saginaw Co.	Reliability - outage minutes avoided	1,080
51		VAN ATTA	495	1	Project	Equipment Replacement and Regulatory	Meridian Twp, Ingham Co.	Regulatory Compliance	-
52		WILLIAMS	413	1	Project	Equipment Replacement and Regulatory	Allegan Twp, Allegan Co.	Regulatory Compliance	-
53		**LVD Substations Rehabilitation Total**	**40,895**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2024-2025 Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1		MOBILE VAULT #1	1,000	1	Project	New Technologies	Statewide		-
2		MOBILE VAULT #2	1,000	1	Project	New Technologies	Statewide		-
3		ELEANOR ST ELEC	704	1	Project	Obsolete or Needed Electrical	Kalamazoo	Customer-outage-minutes avoided	14,944
4		JACKSON ST CIVIL	1,000	1	Project	Obsolete or Needed Civil	Battle Creek	Customer-outage-minutes avoided	-
5		JACKSON ST ELEC	500	1	Project	Obsolete or Needed Electrical	Battle Creek	Customer-outage-minutes avoided	9,421
6		MECHANIC VAULT DF	525	1	Project	Deadfronting	Jackson	Worker Safety	-
7		POST TAVERN VAULT DF	600	1	Project	Deadfronting	Battle Creek	Worker Safety	-
8		**Metro Reliability Total**	**5,329**						

MICHIGAN PUBLIC SERVICE COMMISSION
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Metro Rehabilitation	CORTLAND MECHANIC TO JACKSON CIVIL	1,500	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	-
2		CORTLAND MECHANIC TO JACKSON ELEC	1,000	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	9,011
3		GENESEE CTY COURTHOUSE CIVIL	1,200	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	-
4		GENESEE CTY COURTHOUSE ELEC	400	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	440
5		EAST 1st STREET VAULT CIVIL	750	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	-
6		EAST 1st STREET VAULT ELEC	650	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	41,800
7		BURDICK VAULT	500	1	Project	Vault or Manhole Rehabiliation	Kalamazoo	Customer-outage-minutes avoided	410
8		FRANKLIN ST CIVIL	900	1	Project	Crushed Duct	Saginaw	Customer-outage-minutes avoided	-
9		FRANKLIN ST ELEC	400	1	Project	Crushed Duct	Saginaw	Customer-outage-minutes avoided	14,960
10		NEW FIRESTONE VAULT	687	1	Project	Vault or Manhole Rehabiliation	Grand Rapids	Customer-outage-minutes avoided	11,059
11		**Metro Rehabilitation Total**	**7,987**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Bridge Period 16 Months Ending April 30th, 2026
($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Location
1	System Protection	Breton	600	9	Relay Packages	Line Exit Relay Replacements	Reliability	Grand Rapids
2		Looking Glass	52	1			Reliability	Lansing
3		Willard	105	1			Reliability	Birch Run
4		Engine Plant	150	1			Reliability	Flint
5		East Genesee	440	3			Reliability	Saginaw
6		Muskegon Heights	674	5			Compliance	Muskegon Heights
7		Frame Plant	599	7			Compliance	Flint
8		Hazelwood	48	2			Compliance	Plainwell
9		Baum Street	805	4			Compliance	Saginaw
10		Crotty Working Space	150	1			Compliance	Bay City
11		Loud Hydro	720	4			Compliance	Glennie
12		Harvey Street	1217	10			Compliance	Grand Rapids
13		Trowbridge	596	4			Compliance	Allegan
14		Dow Corning	68	1			Compliance	Midland
15		Barry	544	4			Reliability	Hastings
16		**System Protection Total:**	**6,768**					

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Bridge Period 16 Months Ending April 30th, 2026
($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines and Subs Capacity	WD1108 WILLIAMS - REPL CAP BANK *05	495	1	Projects	Improved Functionality	Safety/New Standards	N/A	Allegan Co.
2	HVD Lines and Subs Capacity	Manchester 46 kV Line – Pole replacements	483	1	Projects	Improved Functionality	Mitigate Inadequate Clearance	N/A	Jackson Co.
3	HVD Lines and Subs Capacity	Saginaw River Bank Replacement	1,295	1	Projects	Improved Functionality	Replace to Standard location/increase capacity/reliability	N/A	Saginaw Co.
4	HVD Lines and Subs Capacity	LN033QQ SHEPHERD RP STR 452-456 *13	220	1	Projects	Improved Functionality	Mitigate Inadequate Clearance	N/A	Isabella Co.
5	HVD Lines and Subs Capacity	LN078I MONTROSE 46KV 5817 SWTCH TO MOAB	150	1	Projects	Improved Functionality	Improve Reliability and Operational Flexability/cust-min saved	17,650	Genesee Co.
6	HVD Lines and Subs Capacity	WD0552 SAGE SUB REMOVAL *05	60	1	Projects	Improved Functionality	Removes equipment no longer needed	N/A	Bay Co.
7	HVD Lines and Subs Capacity	Discovery Way Mobile Pad *05	200	1	Projects	Improved Functionality	Bring up to Standard/Safety/reduce outage duration	N/A	Midland Co.
8	HVD Lines and Subs Capacity	LN019W MECOSTA RBLD 1.3 MI 46 kV % *12	1,168	1	Projects	Improved Functionality	Increase Clearance for LVD project	N/A	Mecosta Co.
9	HVD Lines and Subs Capacity	WD1215 HUGHES RD REVERSE PWR RELAY *05	98	1	Projects	Improved Functionality	Mitigate Overload Risk/Operational Flexability	N/A	Calhoun Co.
10	HVD Lines and Subs Capacity	LN016B HUGHES RD RBLD 0.78 MI 115CU% *05	978	1	Projects	Improved Functionality	Increase Capacity and Operational Flexability	N/A	Branch Co.
11	HVD Lines and Subs Capacity	LN028JJ BATH RBLD 0.96 MILES 3/0 % *05	300	1	Projects	Improved Functionality	Increase Capacity and Operational Flexability	N/A	Ingham Co.
12	HVD Lines and Subs Capacity	WD0151 DELHI REPL 256 VARMASTER *12	350	1	Projects	Improved Functionality	Avoid Overloads	N/A	Ingham Co.
13	HVD Lines and Subs Capacity	WD0559 MONITOR REPL 156 VARMASTER *12	240	1	Projects	Improved Functionality	Avoid Overloads	N/A	Bay Co.
14	HVD Lines and Subs Capacity	WD1262 TIHART REPL 156 VARMASTER *12	350	1	Projects	Improved Functionality	Avoid Overloads	N/A	Ingham Co.
15	HVD Lines and Subs Capacity	Delhi Working Space	825	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Ingham Co.
16	HVD Lines and Subs Capacity	Phillips Working Space	642	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Kalamazoo Co.
17	HVD Lines and Subs Capacity	Looking Glass Working Space	367	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Clinton Co.
18	HVD Lines and Subs Capacity	Deja Working Space	283	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Montcalm Co.
19	HVD Lines and Subs Capacity	Verona Working Space	517	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Calhoun Co.
20	HVD Lines and Subs Capacity	Cork Street Working Space	299	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Kalamazoo Co.
21	HVD Lines and Subs Capacity	Barry Working Space	629	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Barry Co.
22	HVD Lines and Subs Capacity	Felch Rd Working Space	173	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Newaygo Co.
23	HVD Lines and Subs Capacity	Boardman Working Space	775	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Grand Traverse Co.
24	HVD Lines and Subs Capacity	Iosco Working Space	583	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Iosco Co.
25	HVD Lines and Subs Capacity	Gaylord Working Space	187	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Otsego Co.
26	HVD Lines and Subs Capacity	Delaney Working Space	27	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Genesee Co.
27	HVD Lines and Subs Capacity	Pasadena Working Space	181	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Genesee Co.
28	HVD Lines and Subs Capacity	Eureka Working Space	167	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Montcalm Co.
29	HVD Lines and Subs Capacity	Spaulding Working Space	110	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Kent Co.
30	HVD Lines and Subs Capacity	LN033E COLEMAN RBLD 46KV 13.9 MI *07	10,075	1	Projects	Load Carrying Capability and Voltage Support	Avoid Overloads/offset transmission investment, cust-min saved	216,000	Midland Co.
31	HVD Lines and Subs Capacity	Larkin 46 kV Line Rebuild	4,133	1	Projects	Load Carrying Capability and Voltage Support	Mitigate Inadequate Clearance, increase capacity / cust-min saved	59,000	Midland Co.
32	HVD Lines and Subs Capacity	LN111A SARANAC RBLD 4.5 MI 46 kV % *07	1,256	1	Projects	Load Carrying Capability and Voltage Support	Mitigate Inadequate Clearance, increase capacity	N/A	Ionia Co.
33	HVD Lines and Subs Capacity	Baker 138/46kV Substation (Crandall)	1,030	1	Projects	Load Carrying Capability and Voltage Support	Avoid Overloads and low voltage/cust-min saved	703,507	Van Buren Co.
34	HVD Lines and Subs Capacity	LN081K LAMOREAUX 46KV R/W ACQ TREE RIGHT	2,392	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Kent Co.
35	HVD Lines and Subs Capacity	LN105R ALDRICH 46 KV R/W 2.5 MI	180	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Genesee Co.
36	HVD Lines and Subs Capacity	LN119AD Hammond Rd R/W	333	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
37	HVD Lines and Subs Capacity	LN033QQ SHEPHERD RP STR 452-456 *13	650	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Isabella Co.
38	HVD Lines and Subs Capacity	LN032F UNION ST 46KV LINE R/W	983	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
39	HVD Lines and Subs Capacity	LN019W MECOSTA RBLD 1.3 MI 46 kV R/W	400	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Mecosta Co.
40	HVD Lines and Subs Capacity	Benston New 138kV Tap METC R/W	120	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Muskegon Co.
41	HVD Lines and Subs Capacity	Walker 46 kV Line R/W Tree Rights	117	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Kent Co.
42	HVD Lines and Subs Capacity	Real Estate and R/W Support	797	NA	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Statewide
43	HVD Lines and Subs Capacity	WD1213 EUREKA METC RLY CHANGES *08	300	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Montcalm Co.
44	HVD Lines and Subs Capacity	LN095A PEACH RIDGE 46KV RELOC METC *08	126	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Kent Co.
45	HVD Lines and Subs Capacity	WD1249 ALGOMA INST DUALPLT RLY & CCVT*12	573	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Kent Co.
46	HVD Lines and Subs Capacity	WD0270 N BELDING INST AUX CT & CKTSWR*12	563	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Ionia Co.
47	HVD Lines and Subs Capacity	WD0433 FOUR MI METC NORTHRIDGE COORD.*08	880	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Kent Co.
48	HVD Lines and Subs Capacity	Hodenpyl Substation High-Side Rack Reconfiguration	85	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Wexford Co.
49	HVD Lines and Subs Capacity	LN100AB BENSTON SPUR 1.8 MI 138kV LN *08	1,244	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Muskegon Co.
50	HVD Lines and Subs Capacity	Cobb-Dupont-White Lake Rebuild (taps for Nugent Sand, Becker, & Club)	67	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Muskegon Co.
51	HVD Lines and Subs Capacity	Wexford Relaying Upgrades	301	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Wexford Co.
52	HVD Lines and Subs Capacity	Port Sheldon Substation - Replace 199 SOGS with 138 kV Ckt Swr and Relays	198	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Ottawa Co.
53	HVD Lines and Subs Capacity	Wealthy Street Substation - New METC Snowy Station Coordination	1,060	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Kent Co.
54	HVD Lines and Subs Capacity	WD0266 ISLAND RD INST CKT SWRS METC *05	128	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Eaton Co.
55	HVD Lines and Subs Capacity	Summerton Relay Replacement - METC Coord	308	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Isabella Co.
56	HVD Lines and Subs Capacity	WD0565 HOLLAND ROAD INSTALL AUX CTS *05	219	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Saginaw Co.
57	HVD Lines and Subs Capacity	WD0438 DOW CORNING INSTALL AUX CTS *05	241	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Midland Co.
58		**HVD Lines and Substations Capacity Total**	**40,913**						

MICHIGAN PUBLIC SERVICE COMMISSION
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Subs Capacity	ERASTUS	75	1	Project	New Substations	Wise Twp, Isabella Co.	Obligation To Serve - Customers Impacted	1,829
2		MERCURY	409	1	Project	New Substations	Battle Creek Twp, Calhoun Co.	Obligation To Serve - Customers Impacted	5
3		SKYLINE	2,395	1	Project	New Substations	Beaver Creek Twp, Crawford Co.	Obligation To Serve - Customers Impacted	1,757
4		VALENTINE	2,257	1	Project	New Substations	Pavilion Twp, Kalamazoo Co.	Obligation To Serve - Customers Impacted	541
5		ALLENDALE	1,250	1	Project	Increase Capacity at Existing Substation	Allendale Twp, Ottawa Co.	Obligation To Serve - Customers Impacted	2,527
6		ALLIANCE	1,400	1	Project	Increase Capacity at Existing Substation	Monitor Twp, Bay Co.	Obligation To Serve - Customers Impacted	1
7		BAUM STREET	250	1	Project	Increase Capacity at Existing Substation	Saginaw Twp, Saginaw Co.	Obligation To Serve - Customers Impacted	179
8		BIL MAR	250	1	Project	Increase Capacity at Existing Substation	Blendon Twp, Ottawa Co.	Obligation To Serve - Customers Impacted	1,480
9		BILLWOOD	355	1	Project	Increase Capacity at Existing Substation	Windsor Twp, Eaton Co.	Obligation To Serve - Customers Impacted	920
10		COOLEY	3,705	1	Project	Increase Capacity at Existing Substation	City of Kalamazoo, Kalamazoo Co.	Obligation To Serve - Customers Impacted	2,466
11		CUTLERVILLE	1,201	1	Project	Increase Capacity at Existing Substation	Byron Twp, Kent Co.	Obligation To Serve - Customers Impacted	1,071
12		EAST JACKSON	4,225	1	Project	Increase Capacity at Existing Substation	Leoni Twp, Jackson Co.	Obligation To Serve - Customers Impacted	2,079
13		EAST PARIS	17	1	Project	Increase Capacity at Existing Substation	Paris Twp, Kent Co.	Obligation To Serve - Customers Impacted	3
14		FOUR MILE	2,038	1	Project	Increase Capacity at Existing Substation	Walker Twp, Kent Co.	Obligation To Serve - Customers Impacted	4,892
15		HESPERIA	330	1	Project	Increase Capacity at Existing Substation	Denver Twp, Newaygo Co.	Obligation To Serve - Customers Impacted	2,359
16		JOHNSON	908	1	Project	Increase Capacity at Existing Substation	Robinson Twp, Ottawa Co.	Obligation To Serve - Customers Impacted	2,230
17		LINCOLN	4,290	1	Project	Increase Capacity at Existing Substation	Gustin Twp, Alcona Co.	Obligation To Serve - Customers Impacted	2,287
18		NEWARK	400	1	Project	Increase Capacity at Existing Substation	Holly Twp, Oakland Co.	Obligation To Serve - Customers Impacted	1,227
19		NUNICA	856	1	Project	Increase Capacity at Existing Substation	Crockery Twp, Ottawa Co.	Obligation To Serve - Customers Impacted	1,323
20		ROSE CITY	1,130	1	Project	Increase Capacity at Existing Substation	Cummings Twp, Ogemaw Co.	Obligation To Serve - Customers Impacted	3,201
21		SMITH CREEK	495	1	Project	Increase Capacity at Existing Substation	Ogemaw Twp, Ogemaw Co.	Obligation To Serve - Customers Impacted	1,398
22		SURREY	990	1	Project	Increase Capacity at Existing Substation	Surrey Twp, Clare Co.	Obligation To Serve - Customers Impacted	2,458
23		TREMAINE	430	1	Project	Increase Capacity at Existing Substation	Surrey Twp, Clare Co.	Obligation To Serve - Customers Impacted	621
24		**LVD Substations Capacity Total**	**29,656**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Location
1	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in southern Michigan	6,140	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	Southern Michigan
2	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in northwest Michigan	4,340	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	Northwest Michigan
3	HVD Strategic Customers New Business	New 46 kV dedicated customer Substation in west Michigan	3,704	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	West Michigan
4	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in east Michigan	20,758	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	East Michigan
5	HVD Strategic Customers New Business	Two (2) new 138 kV dedicated customer Substations in west Michigan	24,789	2	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	West Michigan
6	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in southeast Michigan	22,965	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	Southeast Michigan
7	HVD Strategic Customers New Business	High Probability Projects	7,349	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	N/A
8		**HVD Strategic Customers New Business Total**	**90,045**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	New Business								
1	Metro New Business	Van Andel Arena Alley Svc	30	1	Project	Metro New Business	Grand Rapids	Secondary Service; Estimated Added Load; kVA	3
2		Mary Free Bed Pediatric Elec	400	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Added Load; kVA	1,000
3		Amphitheater Elec	600	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Added Load; kVA	2,000
4		Soccer Stadium Civil	1,350	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Added Load; kVA	-
5		Event Center Ph 2 Civil	1,500	1	Project	Metro New Business	Kalamazoo	Primary Service; Estimated Added Load; kVA	-
6		Parking Garage Vault Elec	400	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	300
7		Park Street OH Backfeed Temp	40	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	-
8		225 N Rose Svc	450	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	370
9		315 W Michigan Ave Svc	250	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	250
10		115 W Michigan Ave Svc	30	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	3
11		Blackstone Apartments Elec	403	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	720
12		Hayes Hotel Civil	400	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	-
13		Hayes Hotel Elec	200	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	1,200
14		Marian Hall Civil	400	1	Project	Metro New Business	Flint	Secondary Service; Estimated Added Load; kVA	-
15		**Metro New Business Total**	**6,453**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
1	Metro Relocations	DIVISION AVE CIVIL	500	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	257
2		DIVISION AVE ELEC	1,000	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	257
3		DIVISION MICHIGAN TO COREWELL PL CIVIL	2,500	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	257
4		CHERRY ST; SHELDON TO LAGRAVE CIVIL	525	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	36
5		CHERRY ST; LAGRAVE TO LAFAYETTE CIVIL	1,500	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	43
6		RANSOM ST; LYON TO FOUNTAIN CIVIL	2,500	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	2
7		WEALTHY ST BRIDGE ATTACHMENT CIVIL	2,700	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	360
8		DIVISION AVE; MICHIGAN TO COREWELL PL CIVIL	0	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted; Reimbursible	257
9		INGHAM Δ to Y CONVERSION ELEC	1,207	1	Project	Metro Relocations	Jackson	Substation Coordination; customers impacted	149
10		COUNTY ADMIN VAULT CIVIL$	0	1	Project	Metro Relocations	Flint	Coordination of Utilties; customers impacted; Reimbursible	1
11		COUNTY ADMIN VAULT ELEC$	0	1	Project	Metro Relocations	Flint	Coordination of Utilties; customers impacted; Reimbursible	1
12		SAGINAW MEDICAL DIAMOND CIVIL$ PH 1	0	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted; Reimbursible	11
13		SAGINAW MEDICAL DIAMOND CIVIL PH 2	1,632	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted	3
14		SAGINAW MEDICAL DIAMOND CIVIL PH 3	2,030	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted	14
15		SAGINAW MEDICAL DIAMOND ELEC$ PH 1	0	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted; Reimbursible	11
16		**Metro Relocations Total**	**16,094**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines Reliability	Erie	307	8.0	Miles	Line Rebuilds	Customer*Minutes Avoided	204,608	Monroe County
2		Union City	303	7.9	Miles	Line Rebuilds	Customer*Minutes Avoided	0	Calhoun County
3		Nashville	429	11.2	Miles	Line Rebuilds	Customer*Minutes Avoided	138,261	Barry County
4		Merrill	658	4.6	Miles	Line Rebuilds	Customer*Minutes Avoided	43,206	Gration and Saginaw Counties
5		Grand Valley	543	3.8	Miles	Line Rebuilds	Customer*Minutes Avoided	13,878	Kent County
6		Walker	300	2.1	Miles	Line Rebuilds	Customer*Minutes Avoided	76,935	Kent County
7		Hodenpyl	558	3.9	Miles	Line Rebuilds	Customer*Minutes Avoided	83,179	Wexford County
8		Wirtz Rd	3,798	8.0	Miles	Line Rebuilds	Customer*Minutes Avoided	435,498	Gladwin County
9		Cement City	1,073	1.5	Miles	Line Rebuilds	Customer*Minutes Avoided	46,368	Vandercook
10		Saranac	1,645	2.3	Miles	Line Rebuilds	Customer*Minutes Avoided	27,531	Clarksville
11		Nashville	501	0.7	Miles	Line Rebuilds	Customer*Minutes Avoided	8,641	Hastings
12		Nashville 2	17	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	0	Hastings
13		Port Sheldon	358	0.5	Miles	Line Rebuilds	Customer*Minutes Avoided	3	Ottawa County
14		Newaygo	431	0.3	Miles	Line Rebuilds	Customer*Minutes Avoided	5,830	Newaygo
15		Lake Shore	2,310	0.8	Miles	Line Rebuilds	Customer*Minutes Avoided	6,284	Ottawa County
16		Niagara	501	0.7	Miles	Line Rebuilds	Customer*Minutes Avoided	9,524	Saginaw
17		Niagara 2	286	0.4	Miles	Line Rebuilds	Customer*Minutes Avoided	5,442	Saginaw
18		Dietz - Gaylord	1,716	2	Miles	Line Rebuilds	Customer*Minutes Avoided	2,582	Boyne City
19		Mt. Pleasant	2,717	4	Miles	Line Rebuilds	Customer*Minutes Avoided	187,082	Mount Pleasant
20		Goodale	2,074	3	Miles	Line Rebuilds	Customer*Minutes Avoided	76,361	Battle Creek
21		Alden	5,372	-	Miles	Line Rebuilds	Benefit not realized until completion in 2027	-	Antrim County
22		Leslie	6,224	-	Miles	Line Rebuilds	Benefit not realized until completion in 2027	-	Jackson and Ingham Counties
23		Morrice	3,622	-	Miles	Line Rebuilds	Benefit not realized until completion in 2027	-	Shiawasee County
21		Mancelona	481	9.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	287,945	Antrim County
22		Mancelona 2	593	11.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	354,627	Kalkaska Cunty
23		Carson City	904	17.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	607,526	Montcalm County
24		Burr Oak	374	6.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	74,790	Burr Oak
25		Indian River	584	9.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	176,834	Indian River
26		Cannonsburg	483	4.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	78,326	Cannonsburg
27		Merrill	627	6.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	114,589	Gratioit County
28		Ovid	617	6.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	180,540	Elsie
29		Oakwood	165	1.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	65,344	Kalamazoo
30		Hanover	380	3.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	133,607	Spring Arbor
31		Coleman	411	4.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	154,260	Midland County
32		Silicon	401	3.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	63,648	Freeland
33		Pentwater	165	1.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	27,800	Ludington
34		Squires	103	1.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	23,280	Hillsdale
35		Glen Oaks	329	3.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	53,965	Centreville
36		Eaton Rapids	514	5.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	133,175	Eaton County
37		Eaton Rapids 2	411	4.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	106,540	Springport
38		Boardman - Hodenpyl	545	5.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	187,594	Mesick
39		Kent City	175	1.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	42,432	Kent City
40		Stadium	253	2.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	31,766	Kalamazoo
41		Dort - AC	247	2.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	121,452	Genesee County
42		Greenville	154	1.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	42,090	Greenville
43		Greenville 2	175	1.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	23,851	Greenville
44		Greenville 3	123	1.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	16,836	Greenville
45		Getty	588	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2027	-	Muskegon
46		Ithaca	545	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2027	-	Ashley
47		Ithaca 2	152	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2027	-	Ithaca
48		Frost	89	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2027	-	Clare County
49		Frost 2	1,408	-	Miles	Pole Top Rehabilitation	Benefit not realized until completion in 2027	-	Clare County
50		Pole Replacements	33,569	1230	Poles	Pole Replacements	Customer*Minutes Avoided	1,574,016	Various locations statewide
51		Switch Replacements	7,942	55	Switches	Switch Replacements	Customer*Minutes Avoided	56,306	Various locations statewide
52		Pole Top Assembly Replacement	5,658	600	PTAs	Pole Top Assembly Replacements	Customer*Minutes Avoided	1,462,500	
53		Line Sensors	1,759	140	Projects	Line Sensor Deployment	Improve reliability through increased outage detection		Various locations statewide
54		Real Estate	11,000			Right of Way Acquisition	Procure Right of Way needed to support projects		Various locations statewide
55		**HVD Lines Reliability Total**	**107,667**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Substations Reliability	WD0266 ISLAND ROAD REPL 256 SW *10	527	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Eaton
2	HVD Substations Reliability	WD0191 CROTTY REPL 2 BRKRS *09	760	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Bay
3	HVD Substations Reliability	WD1085 Amber Replace 7 Breakers	2100	7	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	4,368	Mason
4	HVD Substations Reliability	WD0596 FRAME PLANT - REPL 2 BRKRS *02	150	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Genesee
5	HVD Substations Reliability	WD0956 Deja Replace 4 Breakers	400	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2495.99975	Montcalm
6	HVD Substations Reliability	WD1160 Vevay Replace 3 Breakers	900	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Ingham
7	HVD Substations Reliability	WD1108 Williams Replace 3 Breakers	900	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Allegan
8	HVD Substations Reliability	WD0951 Looking Glass Replace 4 Breakers	1200	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Ingham
9	HVD Substations Reliability	WD0785 Delaney Reliability Imp (166 Bkr, PTs, bus)	800	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Genesee
10	HVD Substations Reliability	WD1002 Shaffer Replace 6 Breakers	1800	6	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	3,744	Kent
11	HVD Substations Reliability	WD0064 Beecher Replace 2 138kV Oil Breakers	800	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Lenawee
12	HVD Substations Reliability	WD0286 Verona Replace 256 & Cap Bank, add CTs, RP Fence	1100	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Calhoun
13	HVD Substations Reliability	WD0266 Island Road Replace 4 Gas Breakers, Fence, PTs	1800	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Eaton
14	HVD Substations Reliability	WD0692 Beaver Creek Replace 3 Gas Breakers	900	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Crawford
15	HVD Substations Reliability	WD0064 Beecher Replace 5 46kV Gas Breakers	1500	5	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	3,120	Lenawee
16	HVD Substations Reliability	WD1111 Buck Creek Replace 4 Gas Breakers	1200	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Kent
17	HVD Substations Reliability	WD0600 Cornell Replace 3 Gas Breakers	900	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Shiawassee
18	HVD Substations Reliability	WD0191 Crotty Replace 1 Gas Breaker	300	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Bay
19	HVD Substations Reliability	WD0562 Engine Plant Replace 3 Gas Breakers	900	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Genesee
20	HVD Substations Reliability	WD0389 Hazelwood Replace 1 Gas Breaker	300	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Allegan
21	HVD Substations Reliability	WD0203 Lake Shore Replace 2 Gas Breakers	600	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Ottawa
22	HVD Substations Reliability	WD0049 Loud Hydro Replace 1 Gas Breaker	300	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Iosco
23	HVD Substations Reliability	WD0233 Moore Road Replace 2 Gas Breakers	600	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Hillsdale
24	HVD Substations Reliability	WD0555 Page Ave Replace 4 Gas Breakers	1200	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,496	Jackson
25	HVD Substations Reliability	WD1182 Parr Road Replace 3 Gas Breakers	900	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,872	Washtenaw
26	HVD Substations Reliability	WD1170 Samaria Replace 2 Gas Breakers	600	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	1,248	Monroe
27	HVD Substations Reliability	WD0140 Union City Replace 1 Gas Breaker	300	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	624	Calhoun
28	HVD Substations Reliability	WD0585 CHASE REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Lake
29	HVD Substations Reliability	WD0600 CORNELL REPLACE RTU/T1	195	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Shiawassee
30	HVD Substations Reliability	WD0956 DEJA REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Montcalm
31	HVD Substations Reliability	WD0684 IOSCO REPLACE RTU/T1	234	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Iosco
32	HVD Substations Reliability	WD0951 LOOKING GLASS REPLACE RTU/T1	147	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Ingham
33	HVD Substations Reliability	WD1090 SCOTT LAKE REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Allegan
34	HVD Substations Reliability	WD1083 SUMMERTON REPLACE RTU/T1	176	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Isabella
35	HVD Substations Reliability	WD1367 THOMPSON ROAD REPLACE RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Ionia
36	HVD Substations Reliability	WD1203 VROOMAN REPLACE RTU/T1	281	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Safety		Jackson
37	HVD Substations Reliability	WD1170 SAMARIA REPL BATTERY	225	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Monroe
38	HVD Substations Reliability	WD0623 BEAVER CREEK REPL BATTERY	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Crawford
39	HVD Substations Reliability	WD0074 HUDSON REPL BATTERY	75	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Lenawee
40	HVD Substations Reliability	WD0360 Calhoun Replace Moloney PT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Calhoun
41	HVD Substations Reliability	WD0209 Pasadena Replace Moloney SPT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Genesee
42	HVD Substations Reliability	WD0555 Page Ave Replace Moloney SPT	65	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	4,800	Jackson
43	HVD Substations Reliability	WD1368 Broadmoor Replace #1 Cap Bank	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Kent
44	HVD Substations Reliability	WD0231 Mendon Replace #1 Cap Bank	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		St Joseph
45	HVD Substations Reliability	WD0590 Rice Creek Replace #2 Cap Bank	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Calhoun
46	HVD Substations Reliability	WD0560 Riverview Replace #1 Cap Bank	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Kalamazoo
47	HVD Substations Reliability	WD0140 Union City Replace #1 Cap Bank	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Calhoun
48	HVD Substations Reliability	WD0064 Beecher Replace #2 Cap Bank	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Maintain System Voltage		Lenawee
49	HVD Substations Reliability	WD0737 Ravenna Replace 3ph regulator	600	1	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	1,200	Muskegon
50	HVD Substations Reliability	Blanket Batteries Identified during testing	3000	12	projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
51	HVD Substations Reliability	Yard/Animal improvement (HVD or SEC)	1750	7	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	329,238	Various
52	HVD Substations Reliability	Cap bank controlers	600	12	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
53	HVD Substations Reliability	Ladder Remediation	1500	30	projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
54	HVD Substations Reliability	WD0398 SWARTZ CREEK REPL SW & LA's*13	89	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	20,475	Genesee
55	HVD Substations Reliability	WD0387 Dort Replace 8 switches	520	6	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	122,850	Genessee
56	HVD Substations Reliability	WD0007 Muskegon Heights Replace Obsolete Switches	280	8	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	163,800	Muskegon
57	HVD Substations Reliability	WD0560 Riverview Replace Obsolete Switches	400	7	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	143,325	Kalamazoo
58	HVD Substations Reliability	WD0208 Pasadena Replace Obsolete Switches	320	6	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	122,850	Genesee
59	HVD Substations Reliability	WD1002 Shaffer Replace Obsolete Switches	220	6	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	122,850	Kent
60	HVD Substations Reliability	WD0792 MIDDLEVILLE REPL O+C BUSHINGS *13	216	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Barry
61	HVD Substations Reliability	WD1098 PIGEON LAKE REPL O+C BUSHINGS *13	140	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Ottawa
62	HVD Substations Reliability	Emergent Equipment replacements (Bushings, arrestors, Switches)	1000	8	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	556,416	Various
		HVD Substations Reliability Total:	**39,680**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	Transformer Bank Replacements and Si	WD0670 STOVER REPL TB1 *10	1,500	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Antrim
2	Transformer Bank Replacements and Si	WD1722 BUSKIRK NEW 138/46 KV BULK SUB*13	800	1	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Allegan
3	Transformer Bank Replacements and Si	Alma Substations Rebuild (Armory)	6,000	1	Projects	HVD Substation Rebuilds	Benefit not realized until completion	-	Gratiot
4	Transformer Bank Replacements and Si	Blackstone Substation Rebuild	7,974	1	Projects	HVD Substation Rebuilds	Benefit not realized until completion	-	Jackson
5	Transformer Bank Replacements and Si	WD0152 CEMENT CITY RBLD PREP WORK *10	261	1	Projects	HVD Substation Rebuilds	Benefit not realized until completion	0	Jackson
6	Transformer Bank Replacements and Si	WD1169 MECOSTA SUBSTATION RBLD *10	278	1	Projects	HVD Substation Rebuilds	Benefit not realized until completion	0	Mecosta
7	Transformer Bank Replacements and Si	WD0191 CROTTY REPL TB3 *09	2584	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Bay
8	Transformer Bank Replacements and Si	WD1214 GLEANER REPLACE TB NO.1 *10	2500	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Saginaw
9	Transformer Bank Replacements and Si	Progress Payments for TRF	14770						Various
10	Transformer Bank Replacements and Si	ROW for New Substations	1000						Various
11		**Transformer Bank Replacements and Substation RebuildsTotal:**	37,667						
			6,584						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Substations Reliability	ANGELL	375	1	Project	New or Rebuild Substations	Acme Twp, Grand Traverse Co.	Reliability - outage minutes avoided	493,560
2		EAST TAWAS	200	1	Project	New or Rebuild Substations	Baldwin Twp, Iosco Co.	Reliability - outage minutes avoided	4,074,840
3		HARMON ROAD	1,358	1	Project	New or Rebuild Substations	Woodbridge Twp, Hillsdale Co.	Reliability - outage minutes avoided	1,330,560
4		HOUGHTON LAKE	6,644	1	Project	New or Rebuild Substations	Roscommon Twp, Roscommon Co.	Reliability - outage minutes avoided	6,099,840
5		IARGO	2,245	1	Project	New or Rebuild Substations	Oscoda Twp, Iosco Co.	Reliability - outage minutes avoided	223,560
6		MANTON	642	1	Project	New or Rebuild Substations	Cedar Creek Twp, Wexford Co.	Reliability - outage minutes avoided	2,569,320
7		PALO	2,080	1	Project	New or Rebuild Substations	Ronald Twp, Ionia Co.	Reliability - outage minutes avoided	1,055,160
8		PRESCOTT	1,500	1	Project	New or Rebuild Substations	Richland Twp, Ogemaw Co.	Reliability - outage minutes avoided	1,401,840
9		PULLMAN	358	1	Project	New or Rebuild Substations	Lee Twp, Allegan Co.	Reliability - outage minutes avoided	1,994,760
10		REA ROAD	1,175	1	Project	New or Rebuild Substations	Au Sable Twp, Iosco Co.	Reliability - outage minutes avoided	370,440
11		WALDRON	2,055	1	Project	New or Rebuild Substations	Wright Twp, Hillsdale Co.	Reliability - outage minutes avoided	1,050,840
12		WESTPHALIA	358	1	Project	New or Rebuild Substations	Westphalia Twp, Clinton Co.	Reliability - outage minutes avoided	1,126,440
13		MOBILE 26	4,496	1	Project	New Mobile Substation	Statewide	Reliability - outage minutes avoided	-
14		MOBILE 29	4,496	1	Project	New Mobile Substation	Statewide	Reliability - outage minutes avoided	-
15		BELDEN ROAD	100	1	Project	Animal Mitigation	City of Jackson, Jackson Co.	Reliability - outage minutes avoided	120
16		BRIGDEN	100	1	Project	Animal Mitigation	Pennfield Twp, Calhoun Co.	Reliability - outage minutes avoided	120
17		DIETZ ROAD	165	1	Project	Animal Mitigation	Boyne Valley Twp, Charlevoix Co.	Reliability - outage minutes avoided	70,680
18		DISPOSAL PLANT	100	1	Project	Animal Mitigation	City of Saginaw, Saginaw Co.	Reliability - outage minutes avoided	120
19		FLUSHING PARK	100	1	Project	Animal Mitigation	Flushing Twp, Genesee Co.	Reliability - outage minutes avoided	120
20		GULL LAKE	120	1	Project	Animal Mitigation	Ross Twp, Kalamazoo Co.	Reliability - outage minutes avoided	151,080
21		HASTINGS	248	1	Project	Animal Mitigation	City of Hastings, Barry Co.	Reliability - outage minutes avoided	778,440
22		HENDERSON PUMPING	100	1	Project	Animal Mitigation	Richfield Twp, Genesee Co.	Reliability - outage minutes avoided	120
23		MCKINLEY	100	1	Project	Animal Mitigation	Montrose Twp, Genesee Co.	Reliability - outage minutes avoided	120
24		MCNALLY	120	1	Project	Animal Mitigation	Hayes Twp, Charlevoix Co.	Reliability - outage minutes avoided	480
25		MIDLAND TREATMENT	165	1	Project	Animal Mitigation	City of Midland, Midland Co.	Reliability - outage minutes avoided	120
26		SHANTY CREEK	120	1	Project	Animal Mitigation	Kearney Twp, Antrim Co.	Reliability - outage minutes avoided	60,840
27		TERRACE	248	1	Project	Animal Mitigation	City of Muskegon, Muskegon Co.	Reliability - outage minutes avoided	259,800
28		VENICE	165	1	Project	Animal Mitigation	Venice Twp, Shiawassee Co.	Reliability - outage minutes avoided	117,600
29		SILVER LAKE	450	6	Regulators	Regulator Replacements	Garfield Twp, Grand Traverse Co.	Service Quality; number of customers	2,825
30		BROADMOOR TB3	2,310	1	Project	Transformer Replacements	Paris Twp, Kent Co.	Reliability - outage minutes avoided	386,460
31		BROADMOOR TB4	2,310	1	Project	Transformer Replacements	Paris Twp, Kent Co.	Reliability - outage minutes avoided	421,560
32		LAGRAVE	688	1	Project	Transformer Replacements	City of Grand Rapids, Kent Co.	Reliability - outage minutes avoided	25,380
33		SHERMAN	825	1	Project	Transformer Replacements	Wilber Twp, Iosco Co.	Reliability - outage minutes avoided	368,280
34		WALNUT	1,582	1	Project	Transformer Replacements	Burton Twp, Genesee Co.	Reliability - outage minutes avoided	1,263,600
35		ATLAS	214	1	Project	DSCADA Projects	Altas Twp, Genesee Co.	Reliability - outage minutes avoided	333,120
36		BALDWIN	652	1	Project	DSCADA Projects	Pleasant Plains Twp, Lake Co.	Reliability - outage minutes avoided	240,720
37		BEERS	321	1	Project	DSCADA Projects	Gaines Twp, Genesee Co.	Reliability - outage minutes avoided	339,000
38		CARROLLTON	488	1	Project	DSCADA Projects	City of Saginaw, Saginaw Co.	Reliability - outage minutes avoided	150,480
39		CONKLIN PARK	318	1	Project	DSCADA Projects	Croton Twp, Newaygo Co.	Reliability - outage minutes avoided	210,720
40		GODFREY	376	1	Project	DSCADA Projects	Vergennes Twp, Kent Co.	Reliability - outage minutes avoided	141,480
41		HOGSBACK	739	1	Project	DSCADA Projects	Delhi Twp, Ingham Co.	Reliability - outage minutes avoided	778,920
42		MASON	629	1	Project	DSCADA Projects	Vevay Twp, Ingham Co.	Reliability - outage minutes avoided	390,360
43		ROCKFORD	233	1	Project	DSCADA Projects	Algoma Twp, Kent Co.	Reliability - outage minutes avoided	421,680
44		SHERMAN	629	1	Project	DSCADA Projects	Wilber Twp, Iosco Co.	Reliability - outage minutes avoided	40,920
45		WOODWARD	216	1	Project	DSCADA Projects	Selma Twp, Wexford Co.	Reliability - outage minutes avoided	187,680
46		**LVD Substations Reliability Subtotal**	**42,911**						

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	Reliability								
1	LVD Substations Rehabilitation	BALLENGER	468	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	5,321,160
2		COOPER	612	1	Project	Allis Chalmers Substation Transformers	Cooper Twp, Kalamazoo Co.	Reliability - outage minutes avoided	1,897,560
3		FOUNTAIN	612	1	Project	Allis Chalmers Substation Transformers	Battle Creek Twp, Calhoun Co.	Reliability - outage minutes avoided	736,560
4		FRASER PUMPING	282	1	Project	Allis Chalmers Substation Transformers	Fraser Twp, Bay Co.	Reliability - outage minutes avoided	1,080
5		GLADWIN	732	1	Project	Allis Chalmers Substation Transformers	Grout Twp, Gladwin Co.	Reliability - outage minutes avoided	3,852,360
6		GMI	511	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	2,160
7		GODFREY	607	1	Project	Allis Chalmers Substation Transformers	Vergennes Twp, Kent Co.	Reliability - outage minutes avoided	1,273,320
8		GOLDEN	468	1	Project	Allis Chalmers Substation Transformers	Midland Twp, Midland Co.	Reliability - outage minutes avoided	1,510,920
9		HART	175	1	Project	Allis Chalmers Substation Transformers	Hart Twp, Oceana Co.	Reliability - outage minutes avoided	464,400
10		INTERLOCHEN	428	1	Project	Allis Chalmers Substation Transformers	Grant Twp, Grand Traverse Co.	Reliability - outage minutes avoided	957,960
11		JUNCTION PUMPING	282	1	Project	Allis Chalmers Substation Transformers	Monitor Twp, Bay Co.	Reliability - outage minutes avoided	1,080
12		LENNON ROAD	409	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	2,847,960
13		LYONS	500	1	Project	Allis Chalmers Substation Transformers	Lyons Twp, Ionia Co.	Reliability - outage minutes avoided	1,314,360
14		MAYFAIR	409	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	90,540
15		NESTROM	1,635	1	Project	Allis Chalmers Substation Transformers	Fruitland Twp, Muskegon Co.	Reliability - outage minutes avoided	2,444,040
16		OTTAWA BEACH	1,310	1	Project	Allis Chalmers Substation Transformers	Park Twp, Ottawa Co.	Reliability - outage minutes avoided	2,938,680
17		SAGINAW STREET	3,381	1	Project	Allis Chalmers Substation Transformers	Flint Twp, Genesee Co.	Reliability - outage minutes avoided	79,020
18		WALDO	1,725	1	Project	Allis Chalmers Substation Transformers	Midland Twp, Midland Co.	Reliability - outage minutes avoided	3,106,080
19		CAMELOT LAKE	1,783	1	Project	Equipment Replacement and Regulatory	Greendale Twp, Midland Co.	Regulatory Compliance	-
20		FAIRBANKS	2,701	1	Project	Equipment Replacement and Regulatory	City Of Grand Rapids, Kent Co.	Reliability - outage minutes avoided	123,120
21		HUDSONVILLE	495	1	Project	Equipment Replacement and Regulatory	Georgetown Twp, Ottawa Co.	Reliability - outage minutes avoided	739,620
22		KENDRICK	1,485	1	Project	Equipment Replacement and Regulatory	Cascade Twp, Kent Co.	Regulatory Compliance	-
23		MANCELONA	578	1	Project	Equipment Replacement and Regulatory	Mancelona Twp, Antrim Co.	Reliability - outage minutes avoided	2,010,960
24		MAUMEE	330	1	Project	Equipment Replacement and Regulatory	Adrian Twp, Adrian Co.	Regulatory Compliance	-
25		MEADOWBROOKE	600	1	Project	Equipment Replacement and Regulatory	Caledonia Twp, Kent Co.	Regulatory Compliance	-
26		MIDLAND TREATMENT	743	1	Project	Equipment Replacement and Regulatory	Midland Twp, Midland Co.	Regulatory Compliance	-
27		MUSKEGON HEIGHTS	660	1	Project	Equipment Replacement and Regulatory	Muskegon Twp, Muskegon Co.	Reliability - outage minutes avoided	582,120
28		NEW RICHMOND	1,439	1	Project	Equipment Replacement and Regulatory	Manlius Twp, Allegan Co.	Reliability - outage minutes avoided	719,280
29		OHMAN ROAD	949	1	Project	Equipment Replacement and Regulatory	Evart Twp, Osceola Co.	Reliability - outage minutes avoided	3,079,080
30		PORT CALCITE	3,106	1	Project	Equipment Replacement and Regulatory	Rogers Twp, Presque Isle Co.	Reliability - outage minutes avoided	2,147,040
31		STEELCASE	1,733	1	Project	Equipment Replacement and Regulatory	Grand Rapids Twp, Kent Co.	Regulatory Compliance	-
32		**LVD Substations Rehabilitation Total**	**31,147**						

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	Reliability								
1	Metro Reliability	WOLVERINE TO POST TAVERN CIVIL	500	1	Project	Obsolete or Needed Civil	Battle Creek	Customer-outage-minutes avoided	-
2		WOLVERINE TO POST TAVERN ELEC	300	1	Project	Obsolete or Needed Electrical	Battle Creek	Customer-outage-minutes avoided	20,157
3		WILLIAMS VAULT DF	300	1	Project	Deadfronting	Grand Rapids	Worker Safety	-
4		EDWARDS VAULT DF	300	1	Project	Deadfronting	Kalamazoo	Worker Safety	-
5		ELLSWORTH RECONDUCTOR	600	1	Project	Obsolete or Needed Electrical	Grand Rapids	Customer-outage-minutes avoided	103,626
6		GLOBE CASKET CIVIL	1,800	1	Project	Obsolete or Needed Civil	Kalamazoo	Customer-outage-minutes avoided	-
7		GLOBE CASKET ELEC	198	1	Project	Obsolete or Needed Electrical	Kalamazoo	Customer-outage-minutes avoided	3,951
8		**Metro Reliability Total**	**3,998**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Metro Rehabilitation	MASONIC TEMPLE VAULT	500	1	Project	Vault or Manhole Rehabiliation	Grand Rapids	Customer-outage-minutes avoided	1,759
2		BECKER VAULT	500	1	Project	Vault or Manhole Rehabiliation	Grand Rapids	Customer-outage-minutes avoided	3,519
3		WASHINGTON AVE CIVIL	3,600	1	Project	Crushed Duct	Saginaw	Customer-outage-minutes avoided	-
4		WASHINGTON AVE ELEC	1,393	1	Project	Crushed Duct	Saginaw	Customer-outage-minutes avoided	148,272
5		**Metro Rehabilitation Total**	**5,993**						

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	(a)	(b)	(c)	(d)	(e)	(f)		
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected Period Spending (Test)**	**Units**	**Unit Type**	**Investment Category**	**Benefit Type**	**Location**
1	System Protection	Maumee	404	4	Relay Packages	Line Exit Relay Replacements	Compliance	Muskegon Heights
2	System Protection	Shaffer	1,529	7	Relay Packages	Line Exit Relay Replacements	Reliability	Grand Rapids
3	System Protection	Crotty	885	5	Relay Packages	Line Exit Relay Replacements	Reliability	Bay City
4	System Protection	Owosso	600	4	Relay Packages	Line Exit Relay Replacements	Reliability	Owosso
5	System Protection	Elm St	450	3	Relay Packages	Line Exit Relay Replacements	Reliability	Battle Creek
6	System Protection	Dowling	230	1	Relay Packages	Line Exit Relay Replacements	Reliability	Hudson
7		**System Protection Total:**	**4,098**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines and Subs Capacity	Saginaw River Bank Replacement	2,622	1	Projects	Improved Functionality	Replace to Standard location/increase capacity/reliability	N/A	Saginaw Co.
2	HVD Lines and Subs Capacity	LN028JJ BATH RBLD 0.96 MILES 3/0 % *05	600	1	Projects	Improved Functionality	Increase Capacity and Operational Flexability	N/A	Ingham Co.
3	HVD Lines and Subs Capacity	Looking Glass Working Space	811	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Clinton Co.
4	HVD Lines and Subs Capacity	Deja Working Space	567	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Montcalm Co.
5	HVD Lines and Subs Capacity	Verona Working Space	1,033	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Calhoun Co.
6	HVD Lines and Subs Capacity	Barry Working Space	44	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Barry Co.
7	HVD Lines and Subs Capacity	Felch Rd Working Space	346	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Newaygo Co.
8	HVD Lines and Subs Capacity	Gaylord Working Space	374	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Otsego Co.
9	HVD Lines and Subs Capacity	Delaney Working Space	121	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Genesee Co.
10	HVD Lines and Subs Capacity	Pasadena Working Space	369	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Genesee Co.
11	HVD Lines and Subs Capacity	Eureka Working Space	335	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Montcalm Co.
12	HVD Lines and Subs Capacity	Spaulding Working Space	219	1	Projects	Improved Functionality	Regulatory Compliance	N/A	Kent Co.
13	HVD Lines and Subs Capacity	LN111A SARANAC RBLD 4.5 MI 46 kV % *07	1,644	1	Projects	Load Carrying Capability and Voltage Support	Mitigate Inadequate Clearance, increase capacity	N/A	Ionia Co.
14	HVD Lines and Subs Capacity	Linden 46 kV Line Rebuild (Halsey - Oakland)	5,100	1	Projects	Load Carrying Capability and Voltage Support	Avoid Overloads/Increase Capacity	N/A	Genesee Co.
15	HVD Lines and Subs Capacity	Baker 138/46kV Substation (Crandall)	957	1	Projects	Load Carrying Capability and Voltage Support	Avoid Overloads and low voltage/cust-min saved	703,507	Van Buren Co.
16	HVD Lines and Subs Capacity	LN119AD Hammond Rd R/W	667	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
17	HVD Lines and Subs Capacity	LN032F UNION ST 46KV LINE R/W	800	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
18	HVD Lines and Subs Capacity	Walker 46 kV Line R/W Tree Rights	233	1	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Kent Co.
19	HVD Lines and Subs Capacity	Real Estate and R/W support	3,379	N/A	Projects	Right of Way	Procure Right of Way needed to support projects	N/A	Statewide
20	HVD Lines and Subs Capacity	WD0285 Claremont INST CKT SWR	833	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Saginaw Co.
21	HVD Lines and Subs Capacity	LN100AB BENSTON SPUR 1.8 MI 138kV LN *08	957	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Muskegon Co.
22	HVD Lines and Subs Capacity	Cobb-Dupont-White Lake Rebuild (taps for Nugent Sand, Becker, & Club)	243	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Muskegon Co.
23	HVD Lines and Subs Capacity	Wexford Relaying Upgrades	602	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Wexford Co.
24	HVD Lines and Subs Capacity	Port Sheldon Substation - Replace 199 MOABS-SOGS with 138 kV Circuit Switcher and Relay Installation (METC)	1,474	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Ottawa Co.
25	HVD Lines and Subs Capacity	Wealthy Street Substation - New METC Snowy Station Coordination	3,070	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Kent Co.
26	HVD Lines and Subs Capacity	WD0266 ISLAND RD INST CKT SWRS METC *05	1,395	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Eaton Co.
27	HVD Lines and Subs Capacity	Summerton Relay Replacement - METC Coord	617	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Isabella Co.
28	HVD Lines and Subs Capacity	WD0565 HOLLAND ROAD INSTALL AUX CTS *05	35	1	Projects	Transmission Coordination	Meet Contractual Requirements	N/A	Saginaw Co.
		HVD Lines and Substations Capacity Total	**29,447**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025-2026 Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-110 (MLH-4)
Page: 10 of 13
Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Substations Capacity	BELVEDERE	150	1	Project	New Substations	Saugutuck Twp, Allegan Co.	Obligation To Serve - Customers Impacted	1,685
2		CHANNEL	1,022	1	Project	New Substations	City of Manistee, Manistee Co.	Obligation To Serve - Customers Impacted	1,925
3		ERASTUS	2,330	1	Project	New Substations	Wise Twp, Isabella Co.	Obligation To Serve - Customers Impacted	1,829
4		GARMAN FOSTER	100	1	Project	New Substations	Mendon Twp, St Joseph Co.	Obligation To Serve - Customers Impacted	1,707
5		GRAHAM ROAD	50	1	Project	New Substations	Thomas Twp, Saginaw Co.	Obligation To Serve - Customers Impacted	1,627
6		MERCURY	3,014	1	Project	New Substations	Battle Creek Twp, Calhoun Co.	Obligation To Serve - Customers Impacted	5
7		PRATT LAKE	200	1	Project	New Substations	Lowell Twp, Kent Co.	Obligation To Serve - Customers Impacted	1,252
8		QUICKSILVER	4,435	1	Project	New Substations	City of Grand Rapids, Kent Co.	Obligation To Serve - Customers Impacted	7,137
9		RED HAWK	1,128	1	Project	New Substations	Algoma Twp, Kent Co.	Obligation To Serve - Customers Impacted	1,898
10		VALENTINE	7,674	1	Project	New Substations	Pavilion Twp, Kalamazoo Co.	Obligation To Serve - Customers Impacted	541
11		WADSTEN	200	1	Project	New Substations	Keene Twp, Ionia Co.	Obligation To Serve - Customers Impacted	636
12		BOYNE CITY	248	1	Project	Increase Capacity at Existing Substation	City of Boyne City, Charlevoix Co.	Obligation To Serve - Customers Impacted	2,900
13		CUTLERVILLE	124	1	Project	Increase Capacity at Existing Substation	Byron Twp, Kent Co.	Obligation To Serve - Customers Impacted	1,071
14		NUNICA	759	1	Project	Increase Capacity at Existing Substation	Crockery Twp, Ottawa Co.	Obligation To Serve - Customers Impacted	1,323
15		WAKESHA	818	1	Project	Increase Capacity at Existing Substation	Wakeshma Twp, Kalamazoo Co.	Obligation To Serve - Customers Impacted	725
16		**LVD Substations Capacity Total**	**22,251**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending April 30th, 2027
($000)

Case No.: U-21870
Exhibit No.: A-110 (MLH-4)
Page: 11 of 13
Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Location
1	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in East michigan	2,099	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	East Michigan
2	HVD Strategic Customers New Business	New 138 kV dedicated customer Substations in west michigan	14,672	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	West Michigan
3	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in northern michigan	2,550	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	Northern Michigan
4	HVD Strategic Customers New Business	Customer Contribution (New 138 kV customer Substation in northern michigan)	(2,550)	n/a	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	Northern Michigan
5	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in southeast Michigan	20,619	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	Southeast Michigan
6	HVD Strategic Customers New Business	High Probability Projects	6,470	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	N/A
7		**HVD Strategic Customers New Business Total**	**43,860**					

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025-2026 Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-110 (MLH-4)
Page: 12 of 13
Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	New Business								
1	Metro New Business	Soccer Stadium Elec	1,000	1	Project	Primary Service	Grand Rapids	Primary Service; Estimated Added Load, kVA	2,000
2		3 Towers Civil	2,000	1	Project	Primary Service	Grand Rapids	Secondary Service; Estimated Added Load; kVA	-
3		Corewell Residence Elec	200	1	Project	Secondary Service	Grand Rapids	Secondary Service; Estimated Added Load; kVA	500
4		275 Fulton Elec	300	1	Project	Secondary Service	Grand Rapids	Secondary Service; Estimated Added Load; kVA	250
5		Ampitheater Residential Tower Civil	1,500	1	Project	Secondary Service	Grand Rapids	Secondary Service; Estimated Added Load; kVA	-
6		GVSU Blue Dot Civil	600	1	Project	Primary Service	Grand Rapids	Primary Service; Estimated Added Load, kVA	-
7		GVSU Blue Dot Elec	117	1	Project	Primary Service	Grand Rapids	Primary Service; Estimated Added Load, kVA	950
8		City County Building Elec	500	1	Project	Primary Service	Grand Rapids	Primary Service; Estimated Added Load, kVA	900
9		Event Center Elec	1,500	1	Project	Primary Service	Kalamazoo	Primary Service; Estimated Added Load, kVA	3,000
10		Marian Hall Elec	200	1	Project	Metro New Business	Flint	Secondary Service; Estimated Added Load; kVA	450
11		**Metro New Business Total**	**7,917**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025-2026 Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-110 (MLH-4)
Page: 13 of 13
Witness: MLHayward
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
1	Metro Relocations	WEALTHY ST (QUICKSILVER) CIVIL	2,500	1	Project	Metro Relocations	Grand Rapids	Substation Coordination; customers impacted	TBD
2		WEALTHY ST (QUICKSILVER) ELEC	1,500	1	Project	Metro Relocations	Grand Rapids	Substation Coordination; customers impacted	TBD
3		FRONT AVE; MT VERNON TO PEARL CIVIL	2,000	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	3
4		FRONT AVE; MT VERNON TO PEARL ELEC	1,000	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	3
5		FRONT AVE; WEALTHY TO CSX RR CIVIL$	0	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted; Reimbursible	TBD
6		FRONT AVE; WEALTHY TO CSX RR ELEC$	0	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted; Reimbursible	TBD
7		KALAMAZOO AVE CIVIL	7,000	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	21
8		KALAMAZOO AVE ELEC	3,000	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	21
9		CORPORATION ALLEY CASTINGS	30	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	35
10		SAGINAW MEDICAL DIAMOND ELEC$ PH 1	0	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted; Reimbursible	11
11		SAGINAW MEDICAL DIAMOND ELEC PH 2	200	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted	3
12		SAGINAW MEDICAL DIAMOND ELEC PH 3	610	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted	14
13		MICHIGAN AVE CIVIL	2,565	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	274
14		**Metro Relocations Total**	**20,405**						

Substations:

Engineering reviewed each substation and determined its categorization in the Electric Asset Categorization ("EAC") Report based on how the major assets within the substation are used to serve customers.

EAC Account Categories:

Each substation was assigned to one or more categories:

- 138 kV (V1) Bulk Power Substations (Shared: V2,3,4)
- 138 kV (V1) Distribution Substations (Shared: V3,4)
- 138 kV (V1) Substations (V1 Only)
- 69-46 kV (V2) Bulk Power Substations (Shared: V2,3,4)
- 69-46 kV (V2) Distribution Substations (Shared: V3,4)
- 69-46 kV (V2) Substations (V2 Only)
- GSU Substations (Production)
- LVD Substations (Shared V3,4)
- Other Equipment and Facilities

The categories above were chosen to capture both asset voltage and the facilities connected to/relying on that asset. The listed asset voltage (138 kV or 69-46 kV) corresponds to the high-side voltage of the substation. The voltage levels identified in parenthesis (either V1, V2, V3 and/or V4) correspond to the downstream facilities served from that equipment. For reference, the voltage level associated with V1-4 is listed in the table below:

Voltage Category	Facility Voltage (kV)
Voltage 1 (V1)	138 ≥ X > 120 138 kV
Voltage 2 (V2)	120 ≥ X > 25 69 & 46 kV
Voltage 3 (V3)	25 ≥ X > 2.4 LVD- Primary
Voltage 4 (V4)	2.4 kV or less LVD- Secondary

Additional categories were included in the EAC Report to account for GSU or Generation Step-Up facilities, and Other Equipment and Facilities. The latter includes training centers and mobile substations that do not fit into the other categories.

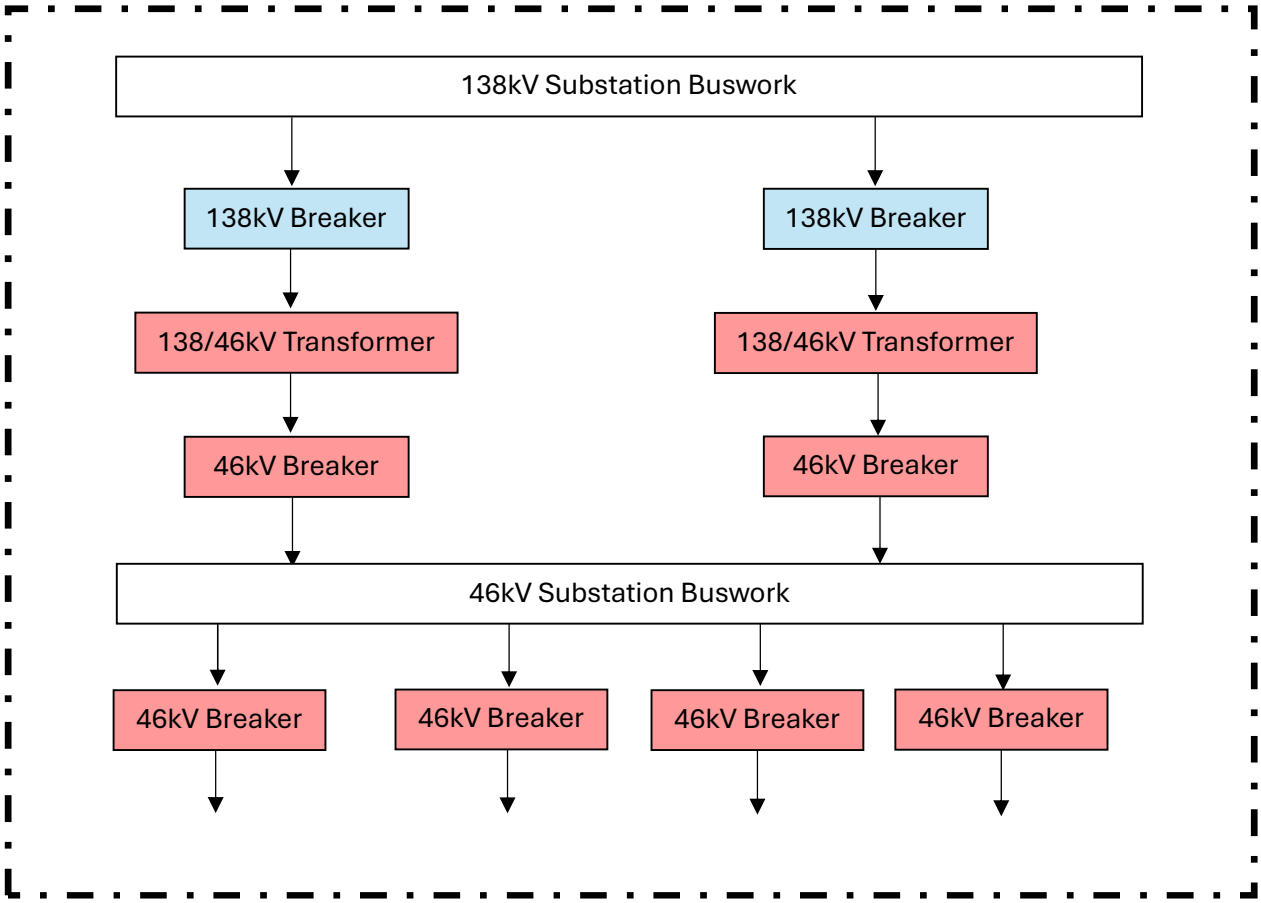
Categorizing Substation Assets:

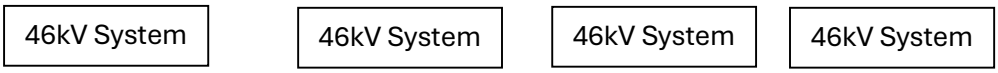
Engineering reviewed substation drawings and engineering records to determine the assignment of substations assets to each EAC category. Where a substation served multiple categories, Engineering calculated the appropriate weighting by reviewing and categorizing the major assets within the substation. The following major assets were included in the categorization:

- Transformers
- 46 kV Voltage regulators
- Breakers
- Bulk capacitors

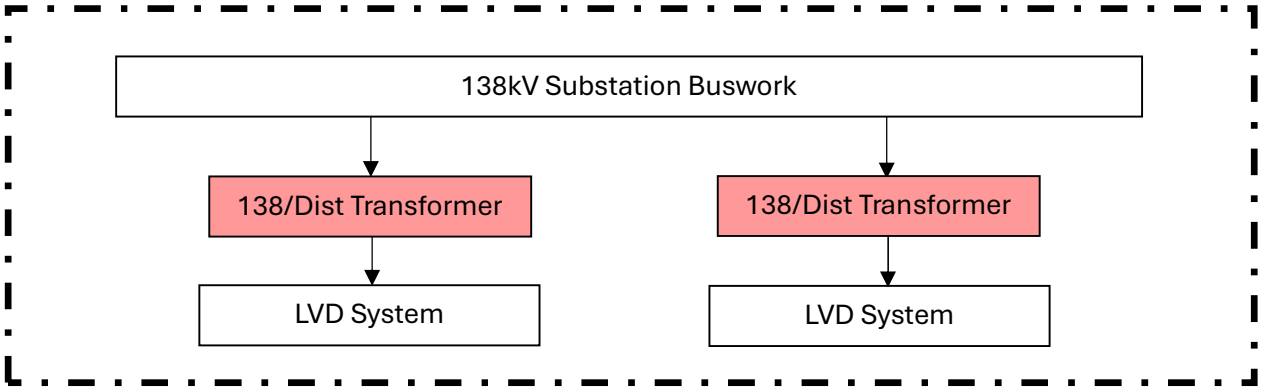
Substation Categorization Examples:

- **Bulk Power Substations (Shared: V2, 3, 4):**
  In the diagram below, the 138 kV equipment shown in **blue** serves all the V2, 3, 4 customers on the underlying 46 kV network. Likewise, all of the 46 kV equipment shown in **red** serves all of the V2, 3, 4 customers on the 46 kV network. At this substation, 20% of the major equipment is 138 kV and 80% of the equipment is 46 kV. Therefore, this substation is categorized as 20% **138 kV (V1) Bulk Power Substation (Shared: V2, 3, 4)** and 80% **69-46 kV (V2) Bulk Power Substation (Shared: V2, 3, 4).**

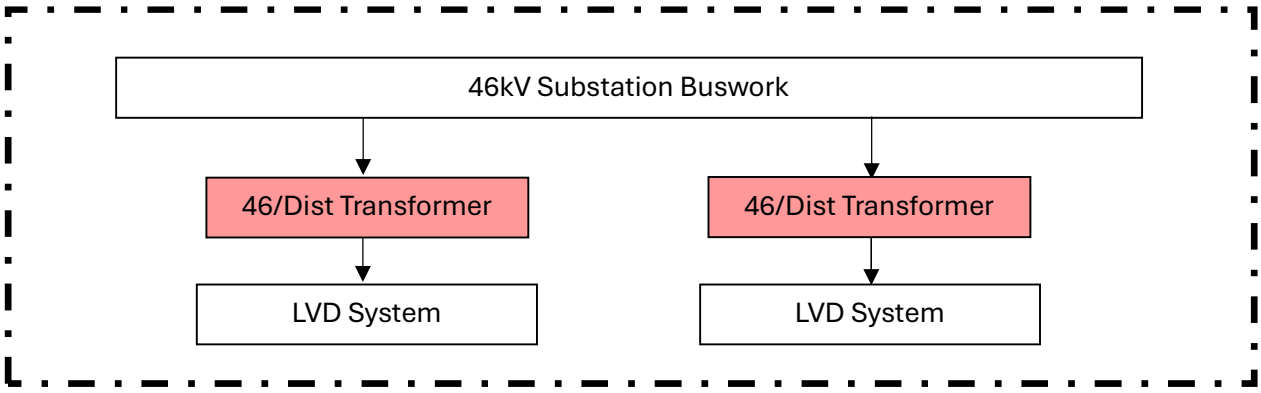




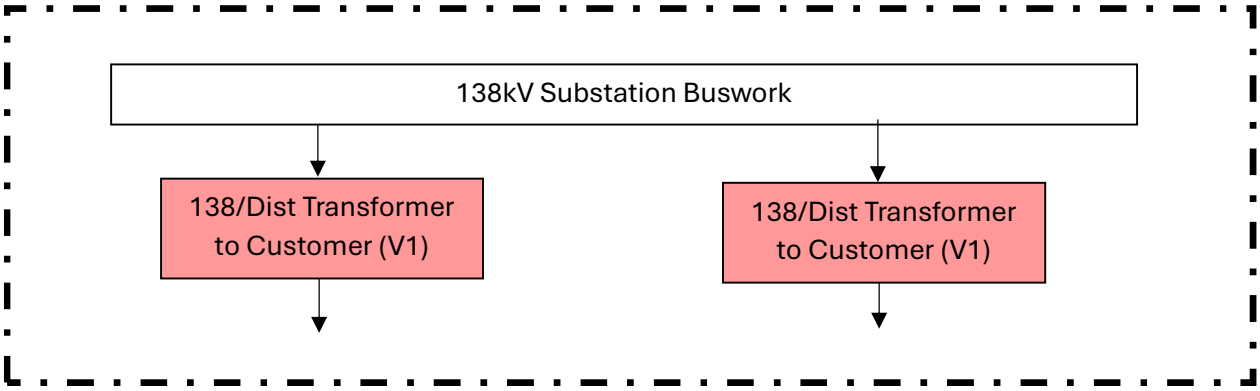
- **Distribution Substation (Shared: V3, 4):**
  In the diagram below, the 138 kV equipment shown in **red** serves V3, 4 customers on the distribution system. At this substation 100% of the major equipment is 138 kV. Therefore, this substation is categorized as 100% **138 kV Distribution Substation (Shared: V3, 4).**



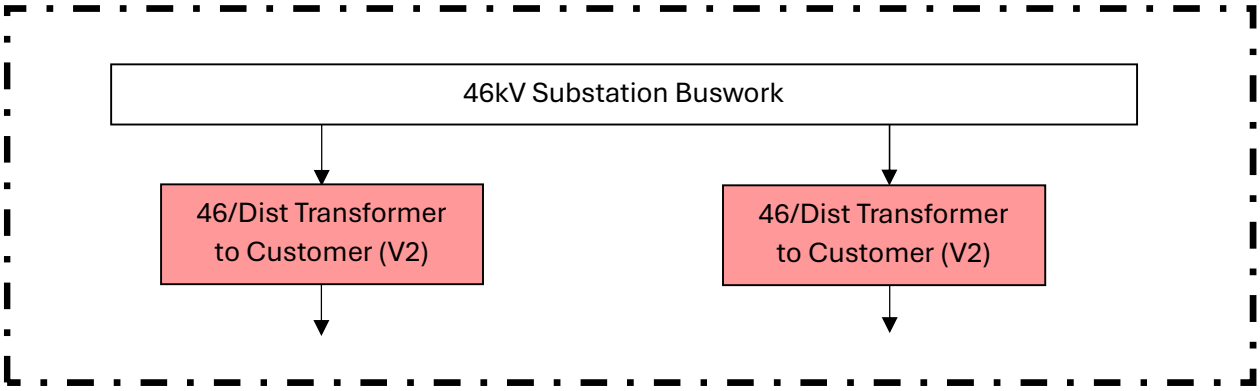
In the diagram below, the 46 kV equipment shown in **red** serves V3, 4 customers on the distribution system. At this substation 100% of the major equipment is 46 kV. Therefore, this substation is categorized as 100% **69-46 kV Distribution Substation (Shared: V3, 4).**



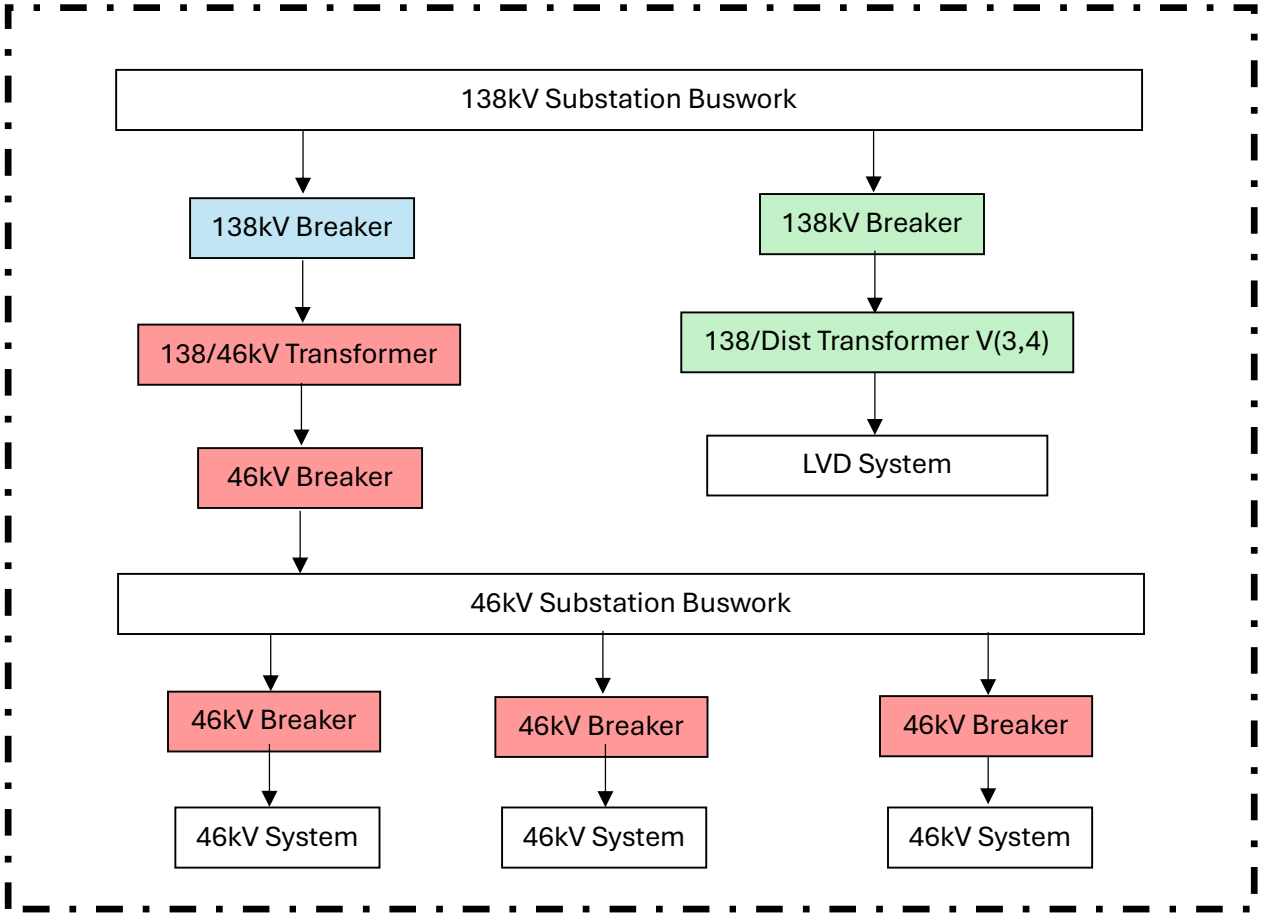
- **138 kV (V1) Substation (V1 only):** In the diagram below, the 138kV equipment shown in **red** serves V1 customers. At this substation 100% of the major equipment is 138 kV. Therefore, this substation is categorized as 100% **138 kV (V1) Substation (V1 only).**



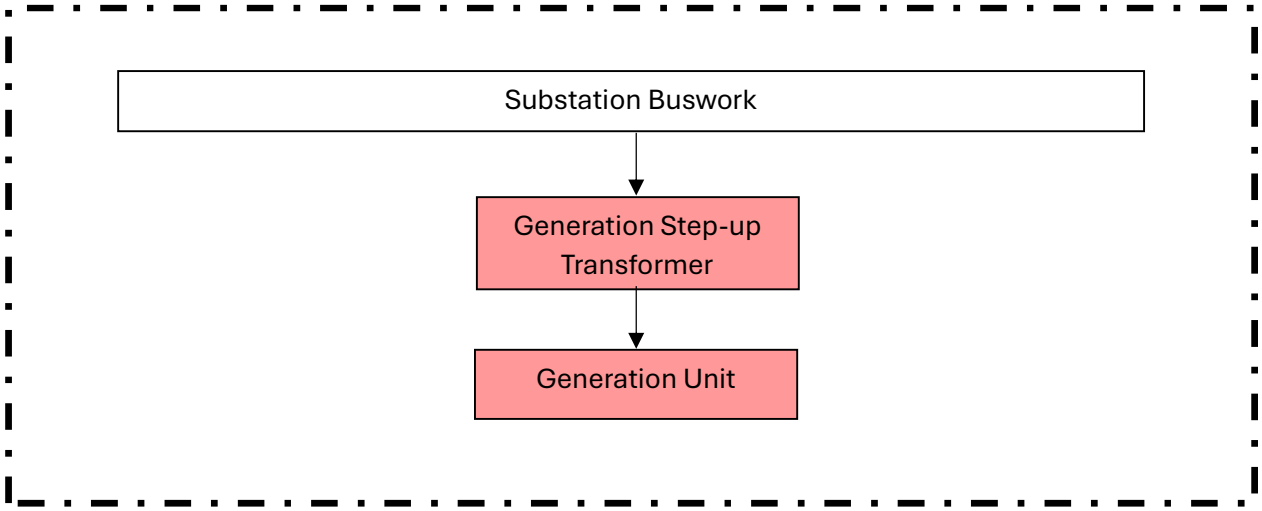
- **69-46 kV Substation (V2 only):** In the diagram below, the 46 kV equipment shown in **red** serves V2 customers. At this substation 100% of the major equipment is 46 kV. Therefore, this substation is categorized as 100% **69-46 kV Substation (V2 only).**



- **Multi-category Substation:** In the diagram below, the 138 kV equipment shown in **blue** serves all of the V2, 3, 4 customers on the underlying 69-46 kV network. Likewise, all of the 46 kV equipment shown in **red** serves all of the V2, 3, 4 customers on the 46 kV network. The equipment shown in **green** serves V3, 4 customers from a 138 kV connection. Therefore, this substation is categorized as 12.5% **138 kV Bulk Power Substation (Shared: V2, 3, 4);** 62.5% **69-46kV Bulk Power Substation (Shared: V2, 3, 4);** and 25% **138kV Substation (Shared: V3, 4).**



- **GSU (Production):** In the diagram below, the equipment shown in **red** serves V2 customers. At this substation, 100% of the major equipment is generation. Therefore, this substation is categorized as 100% **GSU (Production).**



Lines:

Engineering reviewed each line and determined its categorization in the EAC Report based on how the line is used to serve customers.

EAC Account Categories:

Each line was assigned to one of the following categories:

Overhead (OH) Lines:

1. 138 kV (V1) OH Lines (Shared: V1, 3, 4)
2. 138 kV (V1) OH Lines (Shared: V3, 4)
3. 138 kV (V1) OH Lines (V1 Only)
4. 69-46 kV (V2) OH Lines (Shared: V2, 3, 4)
5. 69-46 kV (V2) OH Lines (Shared: V3, 4)
6. 69-46 kV (V2) OH Lines (V2 Only)
7. GSU OH Lines (Production)
8. Other Equipment and Facilities

Underground (UG) Lines:

9. 138 kV (V1) UG Lines (V1 Only)
10. 69-46 kV (V2) UG Lines (Shared: V2, 3, 4)
11. 69-46 kV (V2) UG Lines (Shared: V3, 4)
12. 69-46 kV (V2) UG Lines (V2 Only)
13. GSU UG Lines (Production)
14. Other Equipment and Facilities

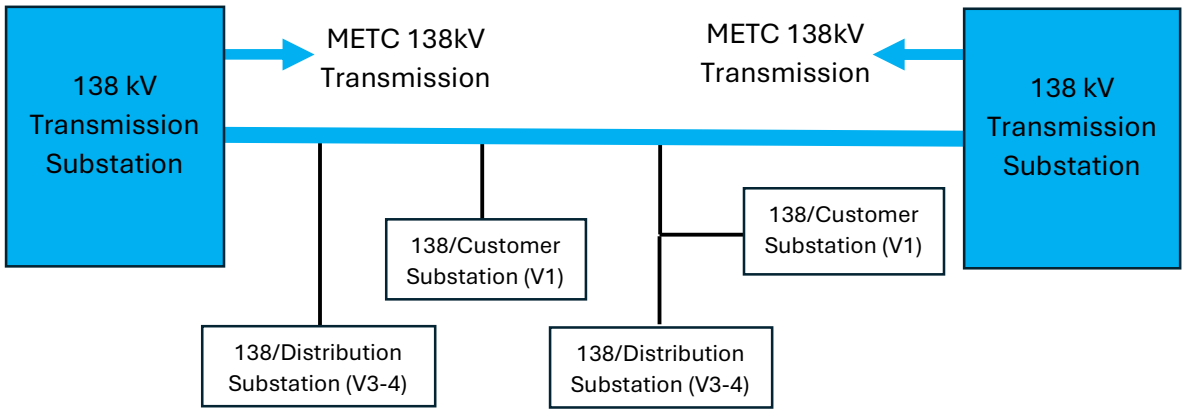
The categories above were chosen to capture whether the line is overhead or underground, energized voltage and the facilities connected to/relying on that asset. The voltage levels identified in parenthesis (either V1, V2, V3 and/or V4) correspond to the downstream facilities served from that equipment.

Additional categories were included in the EAC Report to account for GSU or Generation Step Up facilities and Other Equipment and Facilities. The latter includes training centers that do not fit into the other categories.

Electric System Review – 138 kV Lines:

To identify the EAC Category for a section of 138 kV line, Engineering reviewed the line connections to substations using system diagrams, engineering records, and system models as well as the purpose/use of the substations connected to that section of line.

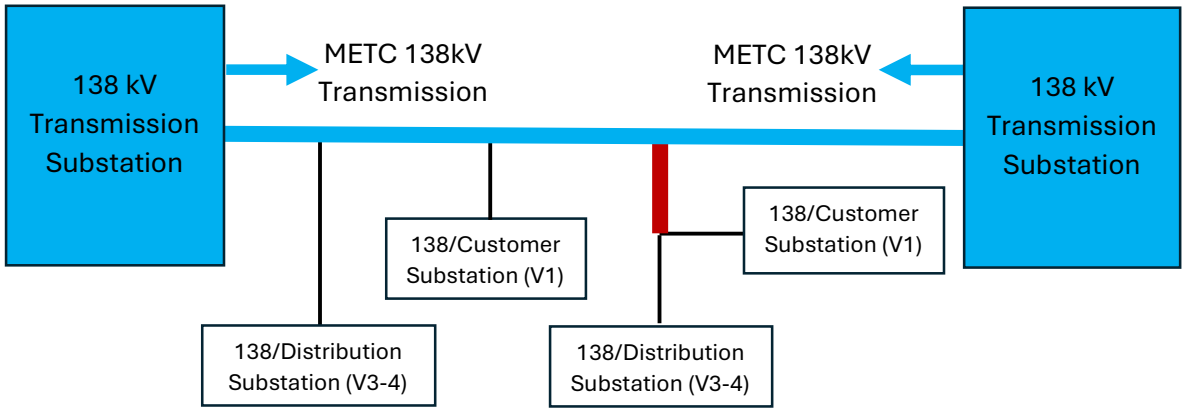
All 138 kV lines which connect to 138 kV Transmission substations form the 138 kV Transmission systems (owned by METC, LLC; Wolverine PSC; et. al.). The transmission system owned by METC is shown in **blue** and the Consumers Energy distribution system is shown in black below.



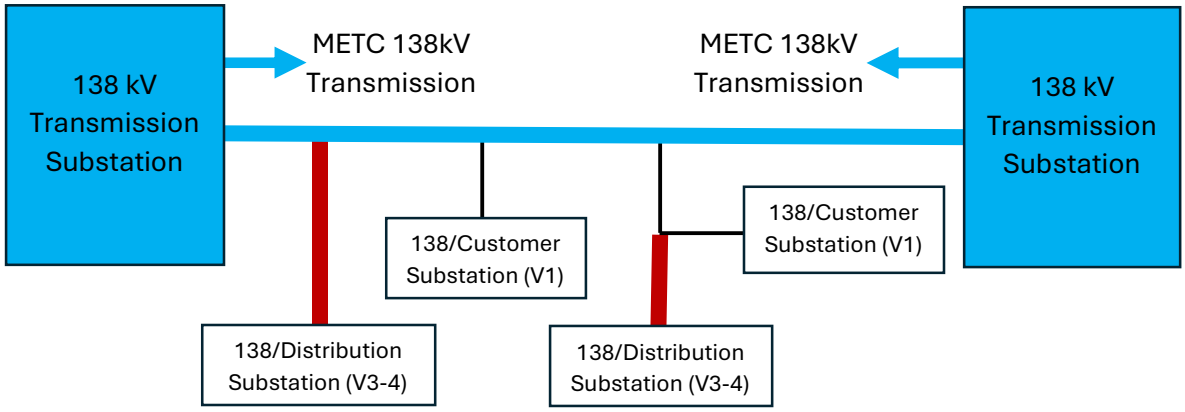
Consumers Energy interconnects its 138 kV Distribution system with the 138 kV Transmission network to serve V1 and V3-4 customers. The Consumers Energy 138 kV lines are categorized by how they connect substations into the 138 kV Transmission system.

138 kV Line Categorization Examples:

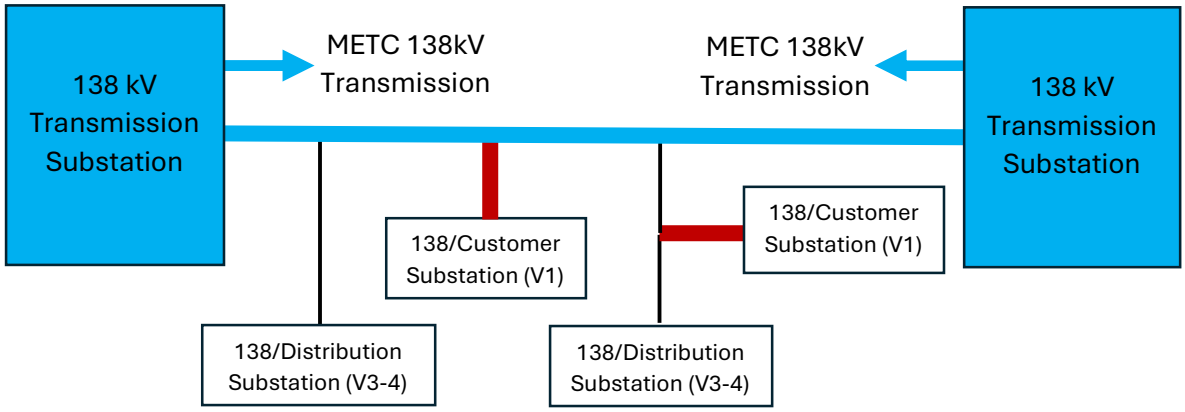
- **138 kV (V1) OH Lines (Shared: V1, 3, 4):**
  In the diagram below, the **red** line section connects to two separate line sections that serve V1 and V3-4 customers. This line section is designated as Shared V1, 3, 4. Based on the line voltage (138 kV) and the line design (Overhead conductor), the line is categorized as **138 kV (V1) OH Lines (Shared: V1, 3, 4).** At present, Consumers Energy does not have 138 kV underground lines serving Shared V1, 3, 4 distribution substations.



- **138 kV (V1) OH Lines (Shared: V3, 4)**: In the diagram below, the **red** line sections connect substations which serve only V3-4 customers. These line sections are designated as Shared V3, 4. Based on the line voltage (138 kV) and the line design (Overhead conductor), the line is categorized as **138 kV (V1) OH Lines (Shared: V3, 4).** At present, Consumers Energy does not have 138 kV underground lines serving V3, 4 distribution substations.



- **138 kV (V1) OH Lines (V1 Only) and 138 kV (V1) UG Lines (V1 Only)**:
In the diagram below, the **red** line sections connect substations which directly serve V1 customers. These line sections are designated as Shared V1. Based on the line voltage (138 kV) and the line design (Overhead or Underground conductor), the line is categorized as **138 kV (V1) OH Lines (V1 Only)** or **138 kV UG Lines (V1 Only).**

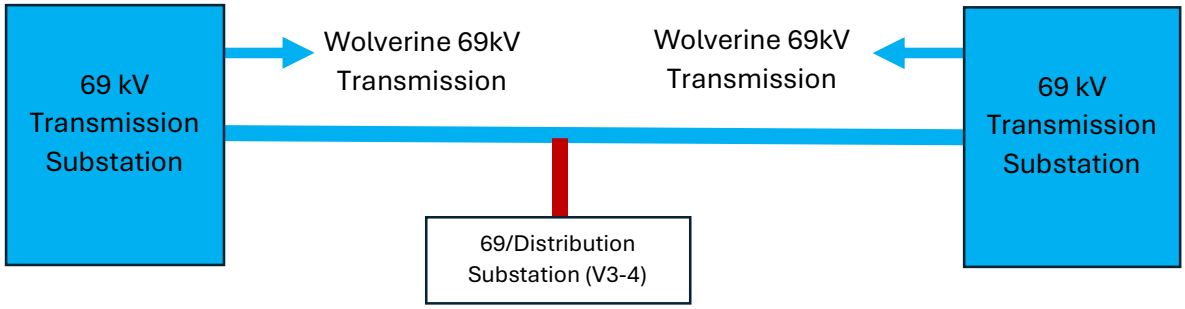


Electric System Review – 69 kV Lines:

To identify the EAC Category for a section of 69 kV line, Engineering reviewed the line connections to substations using system diagrams, engineering records, and system models as well as the purpose/use of the substations connected to that section of line.

All 69 kV Transmission lines to which Consumers Energy substations interconnect are part of the Wolverine PSC 69kV Transmission system. In the diagram below, the Wolverine transmission system is shown in **blue**, and the Consumers Energy 69 kV distribution line is shown in **red.**

At this time, Consumers Energy only has distribution substations serving V3, 4 customers connected to this 69 kV system. In the diagram below, the **red** line section connects to a Consumers Energy 69 kV/distribution substation. This line section is designated as Shared V3, 4. Based on the line voltage (69 kV) and the line design (Overhead conductor or Underground conductor), the line is categorized as **69-46 kV (V2) OH Lines (Shared: V3, 4)** or **69-46 kV (V2) UG Lines (Shared: V3, 4)** respectively**.**

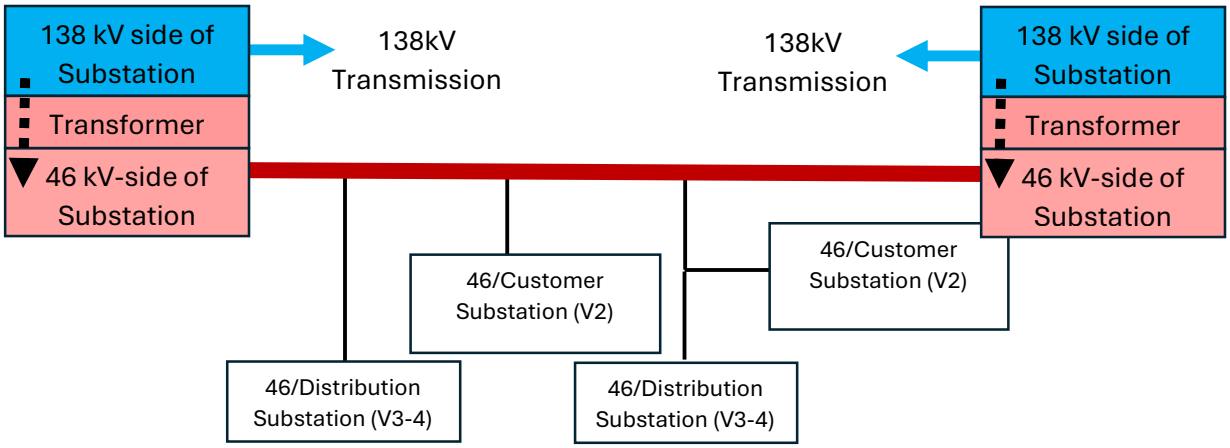


Electric System Review – 46 kV Lines:

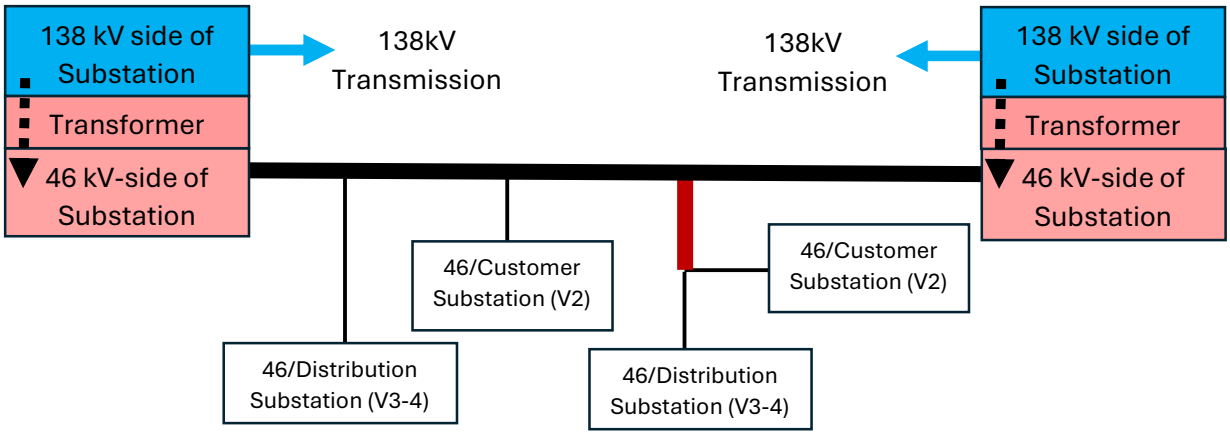
To identify the EAC Category for 46 kV lines Engineering reviewed the line connections to substations using system diagrams, engineering record, and system models as well as the purpose/use of the substations connected to that section of line.

46 kV Line Categorization Examples:

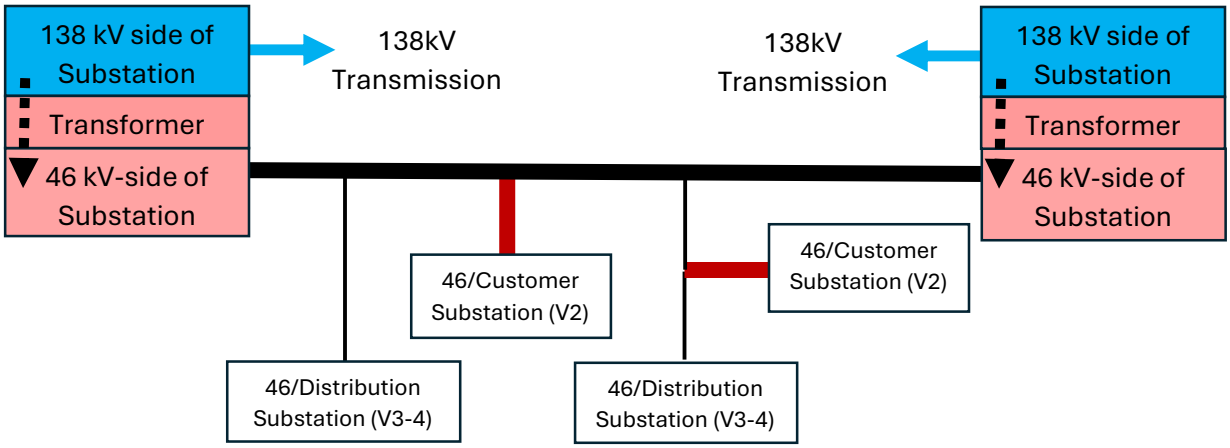
- **69-46 kV Lines (Shared: V2, 3, 4):** In the diagram below, the **red** line section connects 138 kV (high side)/46 kV (low side) bulk power substations. This line serves all interconnected substations and their customers. This line section is designated as Shared V2, 3, 4. Based on the line voltage (46 kV) and the line design (Overhead conductor or Underground conductor), the line is categorized as **69-46 kV (V2) OH Lines (Shared: V2, 3, 4)** or **69-46 kV (V2) UG Lines (Shared: V2, 3, 4)**, respectively**.**



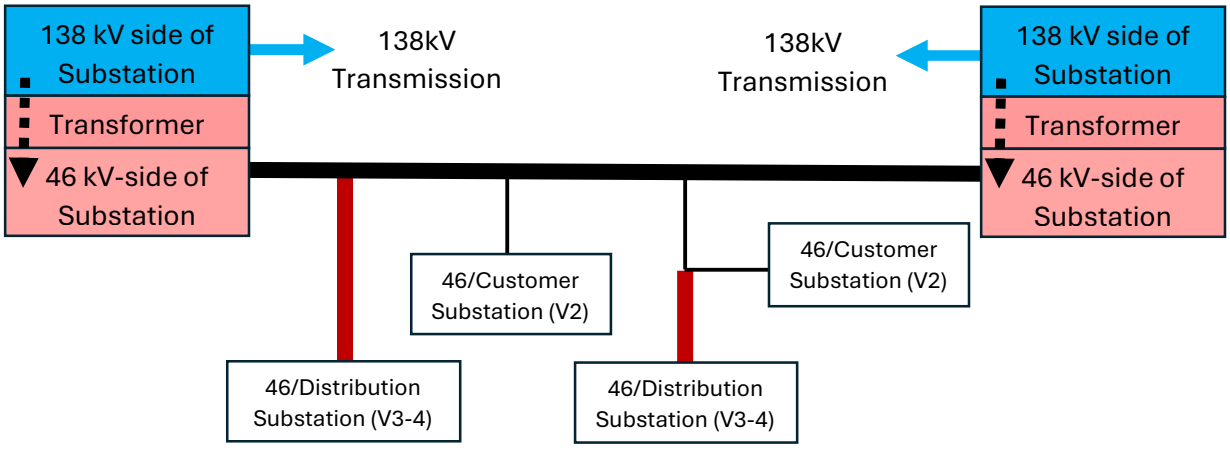
In addition, the line section, shown in **red**, that extends from the bulk power substation line also serves both V2 and V3, 4 substations. This line section also is designated as Shared V2, 3, 4. Based on the line voltage (46 kV) and the line design (Overhead conductor or Underground conductor), the line is categorized as **69-46 kV (V2) OH Lines (Shared: V2, 3, 4)** or **69-46 kV (V2) UG Lines (Shared: V2, 3, 4)**, respectively**.**



- **69-46 kV (V2) Lines (V2 only):** In the diagram below, the **red** line sections connect to 46kV customer substations. This line section is designated as V2 only. Based on the line voltage (46 kV) and the line design (Overhead conductor or Underground conductor), the line is categorized as **69-46 kV (V2) OH Lines (V2 only)** or **69-46 kV (V2) UG Lines (V2 only)**, respectively**.**



- **69-46 kV (V2) Lines (Shared: V3, 4):** In the diagram below, the **red** line sections connect to 46 kV customer substations. This line section is designated as Shared V3, 4. Based on the line voltage (46 kV) and the line design (Overhead conductor or Underground conductor), the line is categorized as **69-46 kV (V2) OH Lines (Shared: V3, 4)** or **69-46 kV (V2) UG Lines (Shared: V3, 4)**, respectively**.**

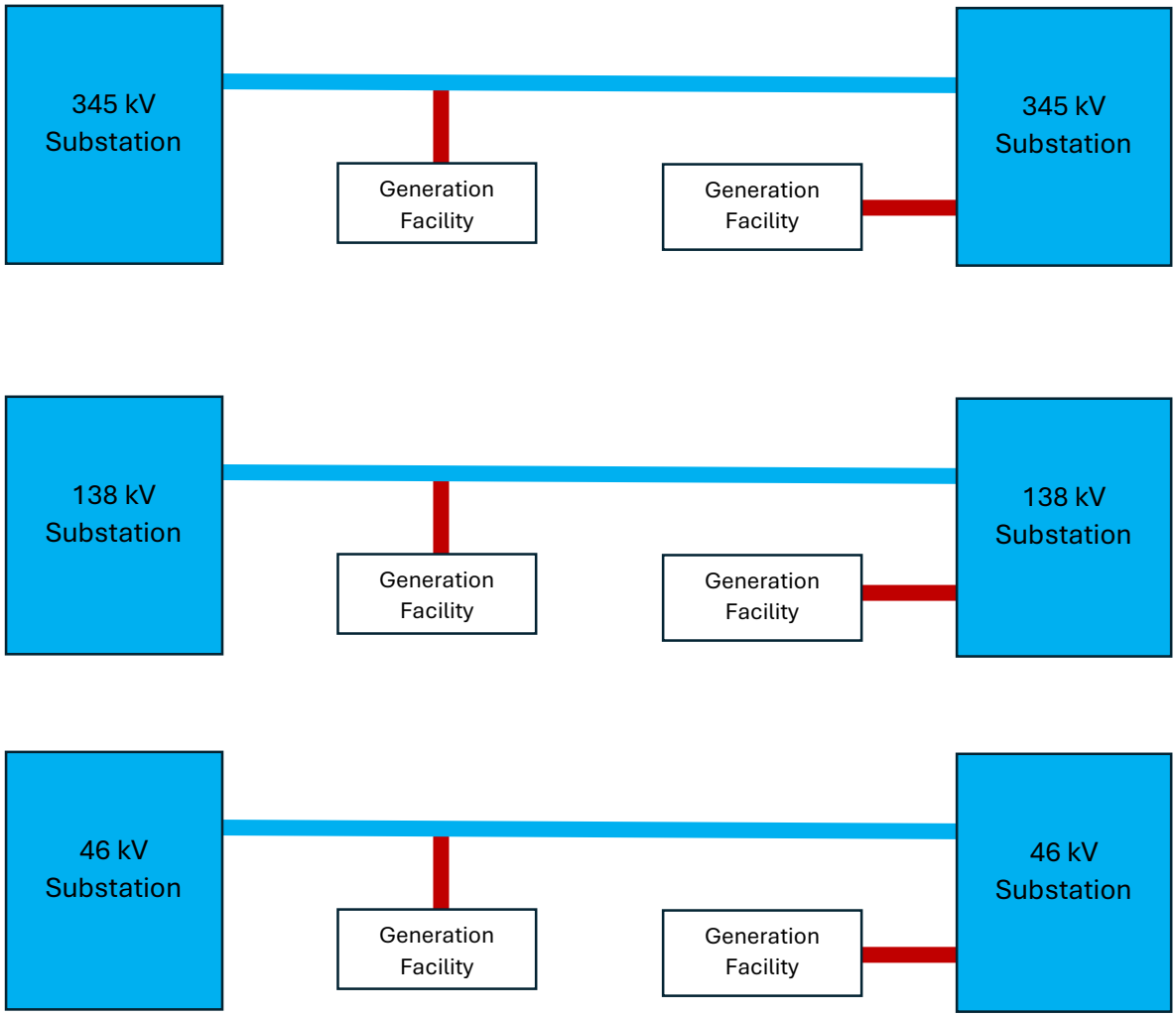


Electric System Review – GSU Lines:

To identify the correct EAC Category for the GSU lines, Engineering reviewed the line connections to substations using system diagrams, engineering record, and system models as well as the purpose/use of the substations connected to that section of line.

Lines that connect generation facilities to the electric network, regardless of voltage level are assigned to GSU. Based on the line design (Overhead conductor or Underground conductor), the line is categorized as **GSU OH Lines** or **GSU UG Lines**, respectively.

In the diagram below, the **red** line sections connect the generation facilities to the respective network or directly into a substation.



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MICHAEL P. KELLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Schedule: B-5.7

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

Case No.: U-21870
Exhibit No.: A-12 (MPK-1)
Schedule: B-5.7
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	New Business Program		308,029	358,808	133,700	492,508	389,759
2	Reliability Program		219,105	404,613	206,293	610,906	697,127
3	Capacity Program		98,235	109,131	33,785	142,916	140,809
4	Demand Failures Program		222,634	189,233	62,835	252,068	185,431
5	Asset Relocation Program		63,767	83,078	32,125	115,203	100,393
6	Electric Other Program		8,669	8,358	2,090	10,448	8,542
7	Wildfire Mitigation & Vulnerable Community		-	-	-	-	30,000
8	**Total Capital**		920,439	1,153,221	470,828	1,624,049	1,552,062
9	IIJA Grant Funding		-	(1,000)	(25,000)	(25,999)	(22,148)
10	**Total Capital net of IIJA Grants**		920,439	1,152,221	445,828	1,598,050	1,529,914

Line No	Description	Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 26 Mos Ending 4/30/2027
11	New Business Program	119,603	372,905	389,759	882,267
12	Reliability Program	134,871	476,035	697,127	1,308,034
13	Capacity Program	36,377	106,539	140,809	283,725
14	Demand Failures Program	63,078	188,991	185,431	437,500
15	Asset Relocation Program	27,693	87,510	100,393	215,596
16	Electric Other Program	2,786	7,662	8,542	18,990
17	Wildfire Mitigation & Vulnerable Community	-	-	30,000	30,000
18	**Total Capital**	384,407	1,239,642	1,552,062	3,176,111
19	IIJA Grant Funding	(333)	(25,667)	(22,148)	(48,148)
20	**Total Capital net of IIJA Grants**	384,074	1,213,976	1,529,914	3,127,963

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

Case No.: U-21870
Exhibit No.: A-112 (MPK-2)
Page: 1 of 2
Witness: MPKelly
Date: June 2025

Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	New Business Program		308,029	358,808	133,700	492,508	389,759
	Contractor		29,916	29,424	10,258	39,682	28,232
	Labor		40,901	45,226	15,380	60,606	47,055
	Materials		140,065	171,874	66,667	238,542	193,137
	Business Expenses		44	46	16	61	38
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		97,102	112,238	41,379	153,617	121,297
2	Reliability Program		219,105	404,613	206,293	610,906	697,127
	Contractor		57,978	109,440	45,504	154,944	143,290
	Labor		28,953	50,193	33,918	84,111	120,116
	Materials		52,287	100,970	47,704	148,674	158,467
	Business Expenses		4,886	7,699	6,037	13,736	22,592
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		75,001	136,311	73,130	209,441	252,662
3	Capacity Program		98,235	109,131	33,785	142,916	140,809
	Contractor		23,441	24,836	7,776	32,612	28,428
	Labor		13,896	16,703	5,034	21,737	24,152
	Materials		26,503	28,879	9,065	37,944	35,824
	Business Expenses		2,077	1,805	600	2,405	1,803
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		32,319	36,908	11,309	48,217	50,602
4	Demand Failures Program		222,634	189,233	62,835	252,068	185,431
	Contractor		22,723	17,557	5,864	23,421	18,215
	Labor		65,819	57,377	18,217	75,594	54,288
	Materials		39,060	32,476	12,725	45,202	34,927
	Business Expenses		206	180	51	231	161
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		94,826	81,643	25,978	107,621	77,841
5	Asset Relocation Program		63,767	83,078	32,125	115,203	100,393
	Contractor		28,177	37,102	14,085	51,187	43,704
	Labor		14,278	19,425	7,212	26,637	22,152
	Materials		14,515	18,838	7,307	26,145	22,865
	Business Expenses		542	556	229	785	742
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		6,255	7,157	3,292	10,449	10,930
6	Electric Other Program		8,669	8,358	2,090	10,448	8,542
	Contractor		949	425	126	551	379
	Labor		53	17	6	22	13
	Materials		7,600	7,821	1,951	9,772	8,059
	Business Expenses		2	0	0	1	0
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		65	95	7	102	91
7	Wildfire Mitigation & Vulnerable Community		-	-	-	-	30,000
	Contractor		-	-	-	-	2,914
	Labor		-	-	-	-	3,984
	Materials		-	-	-	-	13,641
	Business Expenses		-	-	-	-	4
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	9,457
8	**Total Capital**		920,439	1,153,221	470,828	1,624,049	1,552,062
9	IIJA Grant Funding		-	(1,000)	(25,000)	(25,999)	(22,148)
11	**Total Capital net of IIJA Grants & Fleet Savings**		920,439	1,152,221	445,828	1,598,050	1,529,914

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

Case No.: U-21870
Exhibit No.: A-112 (MPK-2)
Page: 2 of 2
Witness: MPKelly
Date: June 2025

	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	26 Mos Ending 4/30/2027
12	New Business Program	119,603	372,905	389,759	882,267
	Contractor	9,808	29,874	28,232	67,913
	Labor	15,075	45,531	47,055	107,661
	Materials	57,291	181,250	193,137	431,679
	Business Expenses	15	46	38	100
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	37,413	116,204	121,297	274,914
13	Reliability Program	134,871	476,035	697,127	1,308,034
	Contractor	36,480	118,464	143,290	298,234
	Labor	16,731	67,380	120,116	204,228
	Materials	33,657	115,017	158,467	307,141
	Business Expenses	2,566	11,170	22,592	36,328
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	45,437	164,004	252,662	462,103
14	Capacity Program	36,377	106,539	140,809	283,725
	Contractor	8,279	24,334	28,428	61,040
	Labor	5,568	16,170	24,152	45,889
	Materials	9,626	28,318	35,824	73,768
	Business Expenses	602	1,803	1,803	4,208
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	12,303	35,915	50,602	98,819
15	Demand Failures Program	63,078	188,991	185,431	437,500
	Contractor	5,852	17,569	18,215	41,636
	Labor	19,126	56,468	54,288	129,882
	Materials	10,825	34,376	34,927	80,129
	Business Expenses	60	171	161	392
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	27,214	80,407	77,841	185,462
16	Asset Relocation Program	27,693	87,510	100,393	215,596
	Contractor	12,367	38,819	43,704	94,890
	Labor	6,475	20,162	22,152	48,789
	Materials	6,279	19,866	22,865	49,010
	Business Expenses	185	600	742	1,528
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	2,386	8,063	10,930	21,379
17	Electric Other Program	2,786	7,662	8,542	18,990
	Contractor	142	409	379	930
	Labor	6	17	13	35
	Materials	2,607	7,165	8,059	17,831
	Business Expenses	0	0	0	1
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	32	70	91	193
18	Wildfire Mitigation & Vulnerable Community	-	-	30,000	30,000
	Contractor	-	-	2,914	2,914
	Labor	-	-	3,984	3,984
	Materials	-	-	13,641	13,641
	Business Expenses	-	-	4	4
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	9,457	9,457
19	**Total Capital**	384,407	1,239,642	1,552,062	3,176,111
20	IIJA Grant Funding	(333)	(25,667)	(22,148)	(48,148)
22	**Total Capital net of IIJA Grants & Fleet Savings**	384,074	1,213,976	1,529,914	3,127,963

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric Distribution
Summary of 5yr Historical Electric Capital Expenditures
($000)

Case No.: U-21870
Exhibit No.: A-113 (MPK-3)
Page: 1 of 2
Witness: MPKelly
Date: June 2025

Line No.	(a) Program / Sub-Program	(b) Witness	(c) 2020 Actuals	(d) 2021 Actuals	(e) 2022 Actuals	(f) 2023 Actuals	(g) 2024 Actuals	(h) 5yr Average	(i) 2025 Projected Bridge Period 12 Mos Ended 12/31/2025	(j) 2025 Projected Bridge Period 4 Mos Ending 4/30/2026	(k) 2025 Projected Bridge Period 16 Mos Ending 4/30/2026	(l) 2026 Projected 12 Mos Ending 4/30/2027	(m) Test Year vs 5yr Ave Variance (l - h)
1	Lines New Business - LVD	JMPartlan	86,752	111,921	128,886	136,185	116,118	115,972	126,458	41,589	168,047	130,200	14,227
2	Large New Business Projects	N/A	-	-	-	-	-	-	-	-	-	-	-
3	Lines Strategic Customers - HVD	MLHayward	4,038	20,268	4,280	11,071	57,836	19,499	67,534	22,511	90,045	43,860	24,361
4	Metro New Business	MLHayward	4,562	2,431	1,865	1,589	11,188	4,327	3,995	2,458	6,453	7,917	3,590
5	Transformers - LVD	JMPartlan	28,857	37,927	49,209	64,137	122,886	60,603	160,821	67,142	227,963	207,782	147,179
6	**New Business**		**124,209**	**172,546**	**184,240**	**212,982**	**308,029**	**200,401**	**358,808**	**133,700**	**492,508**	**389,759**	**189,358**
7	Lines Reliability - LVD	JMPartlan	33,257	39,451	50,631	34,935	64,254	44,506	98,401	82,362	180,763	312,886	268,380
8	Lines Reliability - HVD	MLHayward	22,290	58,092	42,565	21,703	32,264	35,383	98,000	35,667	133,667	107,667	72,284
9	Substations Reliability - LVD	MLHayward	12,583	19,017	16,884	14,709	17,574	16,154	34,381	14,123	48,504	42,911	26,757
10	Substations Reliability - HVD	MLHayward	6,480	3,456	3,993	3,262	5,715	4,581	33,222	14,100	47,322	39,680	35,099
11	System Protection	MLHayward	2,626	2,620	4,504	4,387	4,848	3,797	5,413	1,355	6,768	4,098	301
12	Repetitive Outages - LVD	JMPartlan	4,350	10,714	9,254	4,082	4,491	6,578	10,011	11,078	21,089	30,344	23,766
13	Metro Reliability	MLHayward	3,516	5,737	4,125	3,985	6,690	4,811	3,997	1,332	5,329	3,998	(813)
14	Grid Automation	SAMcPhail	72,264	74,154	52,816	29,038	20,162	49,687	19,268	6,423	25,691	17,837	(31,850)
15	Transformer Bank Replacements and Substation Rebuilds	MLHayward	15,461	29,896	39,184	28,395	26,676	27,922	35,332	11,333	46,666	37,667	9,744
16	Substations Rehabilitation LVD	MLHayward	9,838	18,379	10,941	8,482	13,860	12,300	30,571	10,324	40,895	31,147	18,847
17	Lines Rehabilitation - LVD	JMPartlan	22,331	33,548	29,068	12,530	12,807	22,057	14,823	10,209	25,032	27,135	5,078
18	Metro Rehabilitation	MLHayward	6,181	3,163	4,678	7,034	2,688	4,749	5,990	1,997	7,987	5,993	1,245
19	Grid Storage	N/A	2,552	4,606	643	245	(756)	1,458	-	-	-	-	(1,458)
20	Resiliency	JMPartlan			-	1,438	7,832	3,090	15,204	5,991	21,194	35,765	32,675
21	**Reliability**		**213,729**	**302,834**	**269,285**	**174,225**	**219,105**	**235,835**	**404,613**	**206,293**	**610,906**	**697,127**	**461,292**
22	Lines Capacity - LVD	JMPartlan	9,836	8,217	7,706	2,927	9,424	7,622	21,435	7,145	28,580	54,911	47,289
23	Lines & Subs Capacity - HVD	MLHayward	19,247	17,365	29,292	25,805	27,163	23,775	30,941	9,972	40,913	29,447	5,673
24	Substations Capacity - LVD	MLHayward	10,686	15,068	12,767	14,530	25,887	15,788	22,242	7,414	29,656	22,251	6,464
25	New Business Cap - LVD	JMPartlan	17,767	23,672	27,188	29,054	33,430	26,222	30,122	8,058	38,180	30,130	3,907
26	Conservation Voltage Reduction CVR	JMPartlan	1,937	7,191	3,145	1,311	2,246	3,166	4,391	1,195	5,586	4,070	904
27	Interconnections - LVD Lines	N/A	-	-	-	2	-	0	-	-	-	-	(0)
28	Interconnections - HVD Lines	N/A	-	-	-	-	-	-	-	-	-	-	-
29	Interconnections - LVD Substations	N/A	-	-	-	-	-	-	-	-	-	-	-
30	Interconnections - HVD Substations	N/A	-	-	-	-	85	17	-	-	-	-	(17)
31	**Capacity**		**59,472**	**71,514**	**80,098**	**73,629**	**98,235**	**76,590**	**109,131**	**33,785**	**142,916**	**140,809**	**64,219**
32	Lines Failures - LVD	JMPartlan	105,234	123,531	142,777	159,371	164,356	139,054	145,473	40,587	186,059	128,350	(10,703)
33	Lines & Subs Failures - HVD	MLHayward	6,782	6,050	10,015	13,524	11,705	9,615	4,972	3,324	8,296	10,000	385
34	Substations Failures - LVD	MLHayward	9,175	12,782	8,056	14,869	11,478	11,272	8,942	2,981	11,923	8,961	(2,311)
35	Meters - LVD	JMPartlan	22,589	22,368	30,975	58,653	35,077	33,932	29,299	15,827	45,126	37,770	3,837
36	Metro Failures	MLHayward	1,041	50	122	464	18	339	547	117	664	350	11
37	**Demand Failures**		**144,821**	**164,781**	**191,944**	**246,880**	**222,634**	**194,212**	**189,233**	**62,835**	**252,068**	**185,431**	**(8,780)**
38	Lines Relocations - LVD	JMPartlan	32,961	38,895	52,814	46,848	51,502	44,604	71,880	26,032	97,911	79,090	34,486
39	Lines Relocations - HVD	MLHayward	1,906	1,709	2,565	5,319	845	2,469	898	299	1,197	899	(1,570)
40	Metro Relocations	MLHayward	3,815	6,550	6,888	5,161	11,420	6,767	10,300	5,794	16,094	20,405	13,638
41	**Asset Relocations**		**38,683**	**47,154**	**62,267**	**57,328**	**63,767**	**53,840**	**83,078**	**32,125**	**115,203**	**100,393**	**46,554**
42	Computer & Equipment	MLHayward	2	378	6,273	412	-	1,413	75	-	75	75	(1,338)
43	Tools	JMPartlan	3,611	5,214	5,257	4,560	7,773	5,283	8,004	1,997	10,001	8,248	2,965
44	System Control Projects	MLHayward	976	1,193	2,179	41	896	1,057	279	93	372	219	(838)
45	Facilities Security	N/A	-	-	-	-		-	-	-	-	-	-
46	NERC/NESC Compliance	N/A	-	-	-	-		-	-	-	-	-	-
47	Substation Fall Protection	N/A	-	-	-	-		-	-	-	-	-	-
48	Grid Technologies	N/A	-	-	-	-		-	-	-	-	-	-
49	**Electric Other**		**4,589**	**6,786**	**13,709**	**5,014**	**8,669**	**7,753**	**8,358**	**2,090**	**10,448**	**8,542**	**789**
50	Wildfire Mitigation	MPKelly	-	-	-	-	-	-	-	-	-	-	-
51	Vulnerable Community	MPKelly	-	-	-	-	-	-	-	-	-	30,000	30,000
52	**Wildfire Mitigation & Vulnerable Community**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**30,000**	**30,000**
53	**Total Capital Electric D&T**		**585,504**	**765,614**	**801,543**	**770,057**	**920,439**	**768,631**	**1,153,221**	**470,828**	**1,624,049**	**1,552,062**	**783,431**
54	IIJA Grant Funding	Various	-	-	-	-	-	-	(1,000)	(25,000)	(25,999)	(22,148)	(22,148)
55	**Total Capital net of IIJA Grants**		**585,504**	**765,614**	**801,543**	**770,057**	**920,439**	**768,631**	**1,152,221**	**445,828**	**1,598,050**	**1,529,914**	**761,283**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Electric Distribution
Summary of 5yr Historical Electric Capital Expenditures
($000)

Case No.: U-21870
Exhibit No.: A-113 (MPK-3)
Page: 2 of 2
Witness: MPKelly
Date: June 2025

Line No.	(a) Program / Sub-Program	(b) Witness	(c) 2020 Actuals	(d) 2021 Actuals	(e) 2022 Actuals	(f) 2023 Actuals	(g) 2024 Actuals	(h) 5yr Average	(i) 2025 Projected Bridge Period 4 Mos Ending 4/30/2025	(j) 12 Mos Ending 4/30/2026	(k) 16 Mos Ending 4/30/2027	(l) 2026 Projected 28 Mos Ending 4/30/2027	(m) Test Year vs 5yr Ave Variance (k - h)
56	Lines New Business - LVD	JMPartlan	86,752	111,921	128,886	136,185	116,118	115,972	42,153	125,894	130,200	298,247	14,227
57	Large New Business Projects	N/A	-	-	-	-	-	-	-	-	-	-	-
58	Lines Strategic Customers - HVD	MLHayward	4,038	20,268	4,280	11,071	57,836	19,499	22,511	67,534	43,860	133,905	24,361
59	Metro New Business	JMPartlan	4,562	2,431	1,865	1,589	11,188	4,327	1,332	5,121	7,917	14,370	3,590
60	Transformers - LVD	JMPartlan	28,857	37,927	49,209	64,137	122,886	60,603	53,607	174,356	207,782	435,745	147,179
61	**New Business**		**124,209**	**172,546**	**184,240**	**212,982**	**308,029**	**200,401**	**119,603**	**372,905**	**389,759**	**882,267**	**189,358**
62	Lines Reliability - LVD	JMPartlan	33,257	39,451	50,631	34,935	64,254	44,506	32,800	147,963	312,886	493,649	268,380
63	Lines Reliability - HVD	MLHayward	22,290	58,092	42,565	21,703	32,264	35,383	32,667	101,000	107,667	241,333	72,284
64	Substations Reliability - LVD	JMPartlan	12,583	19,017	16,884	14,709	17,574	16,154	11,460	37,044	42,911	91,415	26,757
65	Substations Reliability - HVD	MLHayward	6,480	3,456	3,993	3,262	5,715	4,581	11,074	36,248	39,680	87,002	35,099
66	System Protection	MLHayward	2,626	2,620	4,504	4,387	4,848	3,797	1,804	4,964	4,098	10,866	301
67	Repetitive Outages - LVD	JMPartlan	4,350	10,714	9,254	4,082	4,491	6,578	3,337	17,752	30,344	51,433	23,766
68	Metro Reliability	JMPartlan	3,516	5,737	4,125	3,985	6,690	4,811	1,332	3,997	3,998	9,327	(813)
69	Grid Automation	SAMcPhail	72,264	74,154	52,816	29,038	20,162	49,687	6,423	19,268	17,837	43,528	(31,850)
72	Lines and Subs Rehabilitation HVD	MLHayward	15,461	29,896	39,184	28,395	26,676	27,922	11,777	34,888	37,667	84,332	9,744
73	Substations Rehabilitation LVD	JMPartlan	9,838	18,379	10,941	8,482	13,860	12,300	10,190	30,704	31,147	72,042	18,847
74	Lines Rehabilitation - LVD	JMPartlan	22,331	33,548	29,068	12,530	12,807	22,057	4,941	20,091	27,135	52,167	5,078
75	Metro Rehabilitation	JMPartlan	6,181	3,163	4,678	7,034	2,688	4,749	1,997	5,990	5,993	13,980	1,245
76	Grid Storage	N/A	2,552	4,606	643	245	(756)	1,458	-	-	-	-	(1,458)
77	Resiliency	JMPartlan	-	-	-	1,438	7,832		5,068	16,126	35,765	56,959	35,765
78	**Reliability**		**213,729**	**302,834**	**269,285**	**174,225**	**219,105**	**235,835**	**134,871**	**476,035**	**697,127**	**1,308,034**	**461,292**
79	Lines Capacity - LVD	JMPartlan	9,836	8,217	7,706	2,927	9,424	7,622	7,145	21,435	54,911	83,491	47,289
80	Lines & Subs Capacity - HVD	MLHayward	19,247	17,365	29,292	25,805	27,163	23,775	10,314	30,600	29,447	70,361	5,673
81	Substations Capacity - LVD	JMPartlan	10,686	15,068	12,767	14,530	25,887	15,788	7,414	22,242	22,251	51,907	6,464
82	New Business Cap - LVD	JMPartlan	17,767	23,672	27,188	29,054	33,430	26,222	10,041	28,140	30,130	68,310	3,907
83	Conservative Voltage Reduction CVR	JMPartlan	1,937	7,191	3,145	1,311	2,246	3,166	1,464	4,122	4,070	9,656	904
84	Interconnections - LVD Lines	N/A	-	-	-	2	-	0	-	-	-	-	(0)
85	Interconnections - HVD Lines	N/A	-	-	-	-	-	-	-	-	-	-	-
86	Interconnections - LVD Substations	N/A	-	-	-	-	-	-	-	-	-	-	-
87	Interconnections - HVD Substations	N/A	-	-	-	-	85	17	-	-	-	-	(17)
88	**Capacity**		**59,472**	**71,514**	**80,098**	**73,629**	**98,235**	**76,590**	**36,377**	**106,539**	**140,809**	**283,725**	**64,219**
89	Lines Failures - LVD	JMPartlan	105,234	123,531	142,777	159,371	164,356	139,054	48,491	137,568	128,350	314,410	(10,703)
90	Lines & Subs Failures - HVD	MLHayward	6,782	6,050	10,015	13,524	11,705	9,615	1,657	6,639	10,000	18,296	385
91	Substations Failures - LVD	JMPartlan	9,175	12,782	8,056	14,869	11,478	11,272	2,981	8,942	8,961	20,884	(2,311)
92	Metering Failures - LVD	JMPartlan	22,589	22,368	30,975	58,653	35,077	33,932	9,766	35,360	37,770	82,896	3,837
93	Metro Failures	JMPartlan	1,041	50	122	464	18	339	182	482	350	1,014	11
94	**Demand Failures**		**144,821**	**164,781**	**191,944**	**246,880**	**222,634**	**194,212**	**63,078**	**188,991**	**185,431**	**437,500**	**(8,780)**
95	Lines Relocations - LVD	JMPartlan	32,961	38,895	52,814	46,848	51,502	44,604	23,960	73,952	79,090	177,001	34,486
96	Lines Relocations - HVD	MLHayward	1,906	1,709	2,565	5,319	845	2,469	299	898	899	2,096	(1,570)
97	Metro Relocations	JMPartlan	3,815	6,550	6,888	5,161	11,420	6,767	3,433	12,661	20,405	36,499	13,638
98	**Asset Relocations**		**38,683**	**47,154**	**62,267**	**57,328**	**63,767**	**53,840**	**27,693**	**87,510**	**100,393**	**215,596**	**46,554**
99	Computer & Equipment	MLHayward	2	378	6,273	412	-	1,413	25	50	75	150	(1,338)
100	Tools	JMPartlan	3,611	5,214	5,257	4,560	7,773	5,283	2,668	7,333	8,248	18,249	2,965
101	System Control Projects	MLHayward	976	1,193	2,179	41	896	1,057	93	279	219	591	(838)
102	Facilities Security	N/A	-	-	-	-	-	-	-	-	-	-	-
103	NERC/NESC Compliance	N/A	-	-	-	-	-	-	-	-	-	-	-
104	Substation Fall Protection	N/A	-	-	-	-	-	-	-	-	-	-	-
105	Grid Technologies	N/A	-	-	-	-	-	-	-	-	-	-	-
106	**Electric Other**		**4,589**	**6,786**	**13,709**	**5,014**	**8,669**	**7,753**	**2,786**	**7,662**	**8,542**	**18,990**	**789**
107	Wildfire Mitigation	MPKelly	-	-	-	-	-	-	-	-	-	-	-
108	Vulnerable Community	MPKelly	-	-	-	-	-	-	-	-	30,000	30,000	30,000
109	**Wildfire Mitigation & Vulnerable Community**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**30,000**	**30,000**	**30,000**
110	**Total Capital Electric D&T**		**585,504**	**765,614**	**801,543**	**770,057**	**920,439**	**768,631**	**384,407**	**1,239,642**	**1,552,062**	**3,176,111**	**783,431**
111	IIJA Grant Funding	Various	-	-	-	-	-	-	(333)	(25,667)	(22,148)	(48,148)	(22,148)
112	**Total Capital net of IIJA Grants**		**585,504**	**765,614**	**801,543**	**770,057**	**920,439**	**768,631**	**384,074**	**1,213,976**	**1,529,914**	**3,127,963**	**761,283**

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Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Lines New Business - LVD		116,118	126,458	41,589	168,047	130,200
	Contractor		16,011	17,436	5,734	23,171	17,952
	Labor		34,342	37,401	12,300	49,701	38,507
	Materials		23,392	25,475	8,378	33,854	26,229
	Business Expenses		14	15	5	20	15
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		42,359	46,131	15,171	61,302	47,496
2	Large New Business Projects		-	-	-	-	-
	Contractor		-	-		-	
	Labor		-	-		-	
	Materials		-	-		-	
	Business Expenses		-	-		-	
	Contingency		-	-		-	
	Other (Loadings, Chargebacks)		-	-		-	
3	Lines Strategic Customers - HVD		57,836	67,534	22,511	90,045	43,860
	Contractor		8,663	10,115	3,372	13,487	6,569
	Labor		2,236	2,611	870	3,481	1,696
	Materials		30,337	35,424	11,808	47,232	23,006
	Business Expenses		25	29	10	38	19
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		16,576	19,355	6,452	25,807	12,570
4	Metro New Business		11,188	3,995	2,458	6,453	7,917
	Contractor		5,242	1,872	1,152	3,024	3,710
	Labor		465	166	102	268	329
	Materials		2,114	755	464	1,219	1,496
	Business Expenses		6	2	1	3	4
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		3,360	1,200	738	1,938	2,378
5	Transformers - LVD		122,886	160,821	67,142	227,963	207,782
	Contractor		-	-	-	-	-
	Labor		3,858	5,048	2,108	7,156	6,523
	Materials		84,222	110,220	46,017	156,237	142,406
	Business Expenses		-	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		34,807	45,552	19,018	64,570	58,853
6	**Total Capital**		308,029	358,808	133,700	492,508	389,759

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	(a)	(b)	(c)	(d)	(e)	(f)
			Projected			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027	
7	Lines New Business - LVD	42,153	125,894	130,200	298,247	
	Contractor	5,812	17,359	17,952	41,123	
	Labor	12,467	37,234	38,507	88,208	
	Materials	8,492	25,362	26,229	60,083	
	Business Expenses	5	15	15	35	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	15,377	45,925	47,496	108,798	
8	Large New Business Projects	-	-	-	-	
	Contractor	-	-	-	-	
	Labor	-	-	-	-	
	Materials	-	-	-	-	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	-	-	-	-	
9	Lines Strategic Customers - HVD	22,511	67,534	43,860	133,905	
	Contractor	3,372	10,115	6,569	20,057	
	Labor	870	2,611	1,696	5,176	
	Materials	11,808	35,424	23,006	70,238	
	Business Expenses	10	29	19	57	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	6,452	19,355	12,570	38,377	
10	Metro New Business	1,332	5,121	7,917	14,370	
	Contractor	624	2,400	3,710	6,734	
	Labor	55	213	329	598	
	Materials	252	968	1,496	2,715	
	Business Expenses	1	3	4	7	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	400	1,538	2,378	4,316	
11	Transformers - LVD	53,607	174,356	207,782	435,745	
	Contractor	-	-	-	-	
	Labor	1,683	5,473	6,523	13,679	
	Materials	36,740	119,497	142,406	298,643	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	15,184	49,386	58,853	123,423	
12	**Total Capital**	119,603	372,905	389,759	882,267	

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Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Lines Reliability - LVD		64,254	98,401	82,362	180,763	312,886
	Contractor		5,073	7,768	6,502	14,271	24,701
	Labor		17,300	26,493	22,175	48,668	84,241
	Materials		11,730	17,964	15,036	33,000	57,120
	Business Expenses		4,430	6,784	5,679	12,463	21,573
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		25,721	39,391	32,970	72,361	125,251
2	Lines Reliability - HVD		32,264	98,000	35,667	133,667	107,667
	Contractor		13,558	41,181	14,988	56,169	45,243
	Labor		731	2,220	808	3,028	2,439
	Materials		8,516	25,868	9,414	35,282	28,419
	Business Expenses		177	537	196	733	590
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		9,282	28,194	10,261	38,455	30,975
3	Substations Reliability - LVD		17,574	34,381	14,123	48,504	42,911
	Contractor		5,740	11,229	4,613	15,842	14,015
	Labor		952	1,862	765	2,626	2,324
	Materials		5,247	10,266	4,217	14,483	12,813
	Business Expenses		119	233	96	329	291
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		5,516	10,791	4,433	15,224	13,468
4	Substations Reliability - HVD		5,715	33,222	14,100	47,322	39,680
	Contractor		1,402	8,151	3,459	11,611	9,736
	Labor		761	4,426	1,878	6,304	5,286
	Materials		1,654	9,614	4,080	13,694	11,483
	Business Expenses		2	10	4	15	12
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		1,896	11,021	4,678	15,699	13,164
5	Grid Automation		20,162	19,268	6,423	25,691	17,837
	Contractor		12,039	11,506	3,835	15,341	10,651
	Labor		371	355	118	473	329
	Materials		2,309	2,206	735	2,942	2,042
	Business Expenses		22	21	7	28	20
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		5,420	5,180	1,727	6,907	4,795

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Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ended 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
8	System Protection	4,848	5,413	1,355	6,768	4,098
	Contractor	1,460	1,630	408	2,038	1,234
	Labor	417	465	116	582	352
	Materials	1,506	1,682	421	2,102	1,273
	Business Expenses	1	1	0	1	1
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	1,464	1,635	409	2,044	1,238
9	Repetitive Outages - LVD	4,491	10,011	11,078	21,089	30,344
	Contractor	748	1,667	1,845	3,512	5,053
	Labor	939	2,094	2,317	4,411	6,347
	Materials	960	2,141	2,369	4,510	6,489
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	1,843	4,109	4,547	8,656	12,455
10	Metro Reliability	6,690	3,997	1,332	5,329	3,998
	Contractor	2,309	1,379	460	1,839	1,380
	Labor	180	108	36	143	108
	Materials	2,116	1,264	421	1,686	1,265
	Business Expenses	115	68	23	91	68
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	1,970	1,177	392	1,570	1,177
11	Transformer Bank Replacements and Substation Rebuilds	26,676	35,332	11,333	46,666	37,667
	Contractor	8,983	11,897	3,816	15,714	12,683
	Labor	1,687	2,234	717	2,950	2,381
	Materials	7,761	10,279	3,297	13,577	10,959
	Business Expenses	10	13	4	17	14
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	8,236	10,909	3,499	14,408	11,629
12	Substations Rehabilitation LVD	13,860	30,571	10,324	40,895	31,147
	Contractor	2,859	6,305	2,129	8,435	6,424
	Labor	1,252	2,761	932	3,693	2,813
	Materials	5,391	11,892	4,016	15,907	12,116
	Business Expenses	2	5	2	7	5
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	4,356	9,608	3,244	12,852	9,789
13	Lines Rehabilitation - LVD	12,807	14,823	10,209	25,032	27,135
	Contractor	2,664	3,084	2,124	5,207	5,645
	Labor	2,430	2,813	1,937	4,750	5,149
	Materials	2,403	2,781	1,915	4,697	5,091
	Business Expenses	1	1	1	2	2
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	5,309	6,144	4,232	10,376	11,248

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14	Metro Rehabilitation	2,688	5,990	1,997	7,987	5,993
	Contractor	692	1,542	514	2,056	1,543
	Labor	281	626	209	835	627
	Materials	858	1,913	638	2,551	1,914
	Business Expenses	0	0	0	0	0
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	856	1,909	636	2,545	1,910
15	Grid Storage	(756)	-	-	-	-
	Contractor	(638)	-	-	-	-
	Labor	(39)	-	-	-	-
	Materials	196	-	-	-	-
	Business Expenses	4	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	(278)	-	-	-	-
16	Resiliency	7,832	15,204	5,991	21,194	35,765
	Contractor	1,091	2,100	811	2,911	4,982
	Labor	1,691	3,737	1,910	5,646	7,721
	Materials	1,639	3,100	1,143	4,244	7,483
	Business Expenses	3	24	26	49	16
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	3,408	6,243	2,101	8,345	15,563
17	**Total Capital**	219,105	404,613	206,293	610,906	697,127

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Line No	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 28 Mos Ending 4/30/2027
18	Lines Reliability - LVD	32,800	147,963	312,886	493,649
	Contractor	2,589	11,681	24,701	38,972
	Labor	8,831	39,837	84,241	132,909
	Materials	5,988	27,012	57,120	90,120
	Business Expenses	2,261	10,202	21,573	34,036
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	13,130	59,231	125,251	197,612
19	Lines Reliability - HVD	32,667	101,000	107,667	241,333
	Contractor	13,727	42,442	45,243	101,411
	Labor	740	2,288	2,439	5,466
	Materials	8,623	26,660	28,419	63,702
	Business Expenses	179	554	590	1,323
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	9,398	29,057	30,975	69,431
20	Substations Reliability - LVD	11,460	37,044	42,911	91,415
	Contractor	3,743	12,099	14,015	29,858
	Labor	621	2,006	2,324	4,950
	Materials	3,422	11,061	12,813	27,296
	Business Expenses	78	251	291	620
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	3,597	11,627	13,468	28,692
21	Substations Reliability - HVD	11,074	36,248	39,680	87,002
	Contractor	2,717	8,893	9,736	21,346
	Labor	1,475	4,829	5,286	11,590
	Materials	3,205	10,489	11,483	25,177
	Business Expenses	3	11	12	27
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	3,674	12,025	13,164	28,863
22	Grid Automation	6,423	19,268	17,837	43,528
	Contractor	3,835	11,506	10,651	25,992
	Labor	118	355	329	802
	Materials	735	2,206	2,042	4,984
	Business Expenses	7	21	20	48
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	1,727	5,180	4,795	11,702
25	System Protection	1,804	4,964	4,098	10,866
	Contractor	543	1,495	1,234	3,272
	Labor	155	427	352	934
	Materials	561	1,542	1,273	3,376
	Business Expenses	0	1	1	2
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	545	1,499	1,238	3,282

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

Case No.: U-21870
Exhibit No.: A-115 (MPK-5)
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Date: June 2025

Line No	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 28 Mos Ending 4/30/2027
26	Repetitive Outages - LVD	3,337	17,752	30,344	51,433
	Contractor	556	2,956	5,053	8,565
	Labor	698	3,713	6,347	10,759
	Materials	714	3,796	6,489	10,998
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	1,370	7,286	12,455	21,111
27	Metro Reliability	1,332	3,997	3,998	9,327
	Contractor	460	1,379	1,380	3,219
	Labor	36	108	108	251
	Materials	421	1,264	1,265	2,951
	Business Expenses	23	68	68	160
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	392	1,177	1,177	2,747
28	Transformer Bank Replacements and Substation Rebuilds	11,777	34,888	37,667	84,332
	Contractor	3,966	11,748	12,683	28,397
	Labor	745	2,206	2,381	5,332
	Materials	3,426	10,150	10,959	24,535
	Business Expenses	4	13	14	31
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	3,636	10,771	11,629	26,037
29	Substations Rehabilitation LVD	10,190	30,704	31,147	72,042
	Contractor	2,102	6,333	6,424	14,859
	Labor	920	2,773	2,813	6,507
	Materials	3,964	11,943	12,116	28,023
	Business Expenses	2	5	5	12
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	3,203	9,650	9,789	22,641
30	Lines Rehabilitation - LVD	4,941	20,091	27,135	52,167
	Contractor	1,028	4,179	5,645	10,852
	Labor	938	3,812	5,149	9,899
	Materials	927	3,770	5,091	9,788
	Business Expenses	0	2	2	4
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	2,048	8,328	11,248	21,624
31	Metro Rehabilitation	1,997	5,990	5,993	13,980
	Contractor	514	1,542	1,543	3,599
	Labor	209	626	627	1,462
	Materials	638	1,913	1,914	4,465
	Business Expenses	0	0	0	0
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	636	1,909	1,910	4,454
32	Grid Storage	-	-	-	-
	Contractor	-	-	-	-
	Labor	-	-	-	-
	Materials	-	-	-	-
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
32	Resiliency	5,068	16,126	35,765	56,959
	Contractor	700	2,211	4,982	7,892
	Labor	1,246	4,401	7,721	13,367
	Materials	1,033	3,210	7,483	11,727
	Business Expenses	8	42	16	65
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	2,081	6,264	15,563	23,907
33	**Total Capital**	134,871	476,035	697,127	1,308,034

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

Case No.: U-21870
Exhibit No.: A-116 (MPK-6)
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Witness: MPKelly
Date: June 2025

Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Lines Capacity - LVD		9,424	21,435	7,145	28,580	54,911
	Contractor		1,159	2,636	879	3,514	6,752
	Labor		2,162	4,917	1,639	6,556	12,596
	Materials		2,108	4,794	1,598	6,392	12,281
	Business Expenses		0	0	0	0	0
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		3,996	9,088	3,029	12,117	23,281
2	Lines & Subs Capacity - HVD		27,163	30,941	9,972	40,913	29,447
	Contractor		8,754	9,972	3,214	13,186	9,490
	Labor		2,544	2,898	934	3,832	2,758
	Materials		9,386	10,692	3,446	14,138	10,176
	Business Expenses		9	10	3	13	10
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		6,470	7,370	2,375	9,745	7,014
3	Substations Capacity - LVD		25,887	22,242	7,414	29,656	22,251
	Contractor		7,239	6,220	2,073	8,293	6,223
	Labor		1,377	1,183	394	1,577	1,183
	Materials		7,715	6,628	2,209	8,838	6,631
	Business Expenses		2,049	1,761	587	2,347	1,761
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		7,507	6,450	2,150	8,601	6,453
4	Lines New Business Cap - LVD		33,430	30,122	8,058	38,180	30,130
	Contractor		5,953	5,363	1,435	6,798	5,365
	Labor		7,149	6,442	1,723	8,165	6,443
	Materials		7,050	6,353	1,700	8,052	6,354
	Business Expenses		2	2	0	2	2
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		13,277	11,963	3,200	15,163	11,966
5	Conservative Voltage Reduction CVR		2,246	4,391	1,195	5,586	4,070
	Contractor		330	645	176	821	598
	Labor		646	1,264	344	1,608	1,171
	Materials		211	412	112	524	382
	Business Expenses		17	33	9	42	31
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		1,042	2,037	554	2,592	1,888
7	Lines Solar Interconnections - LVD		-	-	-	-	-
	Contractor		-	-	-	-	-
	Labor		-	-	-	-	-
	Materials		-	-	-	-	-
	Business Expenses		-	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	-
8	Lines Solar Interconnections - HVD		-	-	-	-	-
	Contractor		-	-	-	-	-
	Labor		-	-	-	-	-
	Materials		-	-	-	-	-
	Business Expenses		-	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	-
9	Subs Solar Interconnections - LVD		-	-	-	-	-
	Contractor		-	-	-	-	-
	Labor		-	-	-	-	-
	Materials		-	-	-	-	-
	Business Expenses		-	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	-
10	Subs Solar Interconnections - HVD		85	-	-	-	-
	Contractor		6	-	-	-	-
	Labor		18	-	-	-	-
	Materials		33	-	-	-	-
	Business Expenses		0	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		28	-	-	-	-
11	**Total Capital**		98,235	109,131	33,785	142,916	140,809

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

Case No.: U-21870
Exhibit No.: A-116 (MPK-6)
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Date: June 2025

Line No	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
12	Lines Capacity - LVD	7,145	21,435	54,911	83,491
	Contractor	879	2,636	6,752	10,267
	Labor	1,639	4,917	12,596	19,152
	Materials	1,598	4,794	12,281	18,673
	Business Expenses	0	0	0	0
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	3,029	9,088	23,281	35,399
13	Lines & Subs Capacity - HVD	10,314	30,600	29,447	70,361
	Contractor	3,324	9,862	9,490	22,676
	Labor	966	2,866	2,758	6,590
	Materials	3,564	10,574	10,176	24,313
	Business Expenses	3	10	10	23
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	2,457	7,288	7,014	16,759
14	Substations Capacity - LVD	7,414	22,242	22,251	51,907
	Contractor	2,073	6,220	6,223	14,516
	Labor	394	1,183	1,183	2,760
	Materials	2,209	6,628	6,631	15,469
	Business Expenses	587	1,761	1,761	4,109
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	2,150	6,450	6,453	15,054
15	Lines New Business Cap - LVD	10,041	28,140	30,130	68,310
	Contractor	1,788	5,011	5,365	12,163
	Labor	2,147	6,018	6,443	14,608
	Materials	2,118	5,935	6,354	14,406
	Business Expenses	1	2	2	4
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	3,988	11,175	11,966	27,129
16	Conservative Voltage Reduction CVR	1,464	4,122	4,070	9,656
	Contractor	215	606	598	1,419
	Labor	421	1,186	1,171	2,779
	Materials	137	387	382	906
	Business Expenses	11	31	31	72
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	679	1,913	1,888	4,480
17	Lines Solar Interconnections - LVD	-	-	-	-
	Contractor	-	-	-	-
	Labor	-	-	-	-
	Materials	-	-	-	-
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
18	Lines Solar Interconnections - HVD	-	-	-	-
	Contractor	-	-	-	-
	Labor	-	-	-	-
	Materials	-	-	-	-
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
19	Subs Solar Interconnections - LVD	-	-	-	-
	Contractor	-	-	-	-
	Labor	-	-	-	-
	Materials	-	-	-	-
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
20	Subs Solar Interconnections - HVD	-	-	-	-
	Contractor	-	-	-	-
	Labor	-	-	-	-
	Materials	-	-	-	-
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
21	**Total Capital**	36,377	106,539	140,809	283,725

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Failures Program Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-21870
Exhibit No.: A-117 (MPK-7)
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Witness: MPKelly
Date: June 2025

Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Lines Failures - LVD		164,356	145,473	40,587	186,059	128,350
	Contractor		16,245	14,378	4,011	18,390	12,686
	Labor		53,931	47,735	13,318	61,053	42,117
	Materials		17,882	15,827	4,416	20,243	13,964
	Business Expenses		198	175	49	224	154
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		76,100	67,357	18,793	86,150	59,429
2	Lines & Subs Failures - HVD		11,705	4,972	3,324	8,296	10,000
	Contractor		5,415	2,300	1,538	3,838	4,626
	Labor		905	385	257	642	773
	Materials		1,984	843	563	1,406	1,695
	Business Expenses		4	2	1	3	4
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		3,397	1,443	965	2,407	2,902
3	Substations Failures - LVD		11,478	8,942	2,981	11,923	8,961
	Contractor		905	705	235	940	707
	Labor		1,840	1,433	478	1,911	1,436
	Materials		4,823	3,757	1,252	5,009	3,765
	Business Expenses		3	2	1	3	2
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		3,908	3,045	1,015	4,060	3,051
4	Metering - LVD		35,077	29,299	15,827	45,126	37,770
	Contractor		157	131	71	202	169
	Labor		9,137	7,632	4,123	11,754	9,838
	Materials		14,370	12,003	6,484	18,487	15,473
	Business Expenses		1	1	0	1	1
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		11,412	9,533	5,149	14,682	12,289
5	Metro Failures		18	547	117	664	350
	Contractor		1	43	9	52	27
	Labor		6	193	41	234	123
	Materials		1	46	10	56	30
	Business Expenses		-	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		9	266	57	322	170
6	**Total Capital**		222,634	189,233	62,835	252,068	185,431

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Failures Program Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

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Line No	(a)	(b)	(c)	(d)	(e)	(f)
			Projected			
		4 Mos Ending 4/30/2025	**12 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**28 Mos Ending 4/30/2027**	
7	Lines Failures - LVD	48,491	137,568	128,350	314,410	
	Contractor	4,793	13,597	12,686	31,075	
	Labor	15,912	45,141	42,117	103,170	
	Materials	5,276	14,967	13,964	34,208	
	Business Expenses	58	165	154	378	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	22,452	63,697	59,429	145,579	
8	Lines & Subs Failures - HVD	1,657	6,639	10,000	18,296	
	Contractor	767	3,071	4,626	8,464	
	Labor	128	513	773	1,415	
	Materials	281	1,125	1,695	3,102	
	Business Expenses	1	2	4	6	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	481	1,926	2,902	5,309	
9	Substations Failures - LVD	2,981	8,942	8,961	20,884	
	Contractor	235	705	707	1,647	
	Labor	478	1,433	1,436	3,347	
	Materials	1,252	3,757	3,765	8,774	
	Business Expenses	1	2	2	5	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	1,015	3,045	3,051	7,111	
10	Metering - LVD	9,766	35,360	37,770	82,896	
	Contractor	44	158	169	371	
	Labor	2,544	9,210	9,838	21,592	
	Materials	4,001	14,486	15,473	33,960	
	Business Expenses	0	1	1	2	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	3,178	11,505	12,289	26,971	
11	Metro Failures	182	482	350	1,014	
	Contractor	14	38	27	79	
	Labor	64	170	123	358	
	Materials	15	41	30	86	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	89	234	170	492	
12	**Total Capital**	63,078	188,991	185,431	437,500	

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

Case No.: U-21870
Exhibit No.: A-118 (MPK-8)
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Witness: MPKelly
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ended 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Lines Relocations - LVD	51,502	71,880	26,032	97,911	79,090
	Contractor	23,319	32,545	11,787	44,332	35,810
	Labor	13,245	18,485	6,695	25,180	20,340
	Materials	11,565	16,140	5,845	21,986	17,759
	Business Expenses	38	54	19	73	59
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	3,335	4,655	1,686	6,341	5,122
2	Lines Relocations - HVD	845	898	299	1,197	899
	Contractor	1,087	1,155	385	1,540	1,156
	Labor	47	50	17	66	50
	Materials	229	243	81	324	243
	Business Expenses	300	319	106	425	319
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	(817)	(868)	(289)	(1,158)	(869)
3	Metro Relocations	11,420	10,300	5,794	16,094	20,405
	Contractor	3,771	3,401	1,913	5,315	6,738
	Labor	987	890	501	1,391	1,763
	Materials	2,722	2,455	1,381	3,835	4,863
	Business Expenses	204	184	103	287	364
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	3,737	3,370	1,896	5,266	6,677
4	**Total Capital**	63,767	83,078	32,125	115,203	100,393

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

Case No.: U-21870
Exhibit No.: A-118 (MPK-8)
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Witness: MPKelly
Date: June 2025

Line No	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
5	Lines Relocations - LVD	23,960	73,952	79,090	177,001
	Contractor	10,848	33,483	35,810	80,141
	Labor	6,162	19,018	20,340	45,519
	Materials	5,380	16,605	17,759	39,745
	Business Expenses	18	55	59	132
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	1,552	4,789	5,122	11,463
6	Lines Relocations - HVD	299	898	899	2,096
	Contractor	385	1,155	1,156	2,696
	Labor	17	50	50	116
	Materials	81	243	243	567
	Business Expenses	106	319	319	744
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	(289)	(868)	(869)	(2,027)
7	Metro Relocations	3,433	12,661	20,405	36,499
	Contractor	1,134	4,181	6,738	12,053
	Labor	297	1,094	1,763	3,154
	Materials	818	3,017	4,863	8,698
	Business Expenses	61	226	364	652
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	1,123	4,143	6,677	11,942
8	**Total Capital**	27,693	87,510	100,393	215,596

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

Case No.: U-21870
Exhibit No.: A-119 (MPK-9)
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Witness: MPKelly
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Computer & Equipment	-	75	-	75	75
	Contractor	-	-	-	-	-
	Labor	-	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	75	-	75	75
2	Tools	7,773	8,004	1,997	10,001	8,248
	Contractor	180	185	46	231	191
	Labor	-	-	-	-	-
	Materials	7,593	7,819	1,951	9,770	8,057
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
3	System Control Projects	896	279	93	372	219
	Contractor	769	239	80	319	188
	Labor	53	17	6	22	13
	Materials	7	2	1	3	2
	Business Expenses	2	0	0	1	0
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	65	20	7	27	16
4	Facilities Security	-	-	-	-	-
	Contractor	-	-	-	-	-
	Labor	-	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
5	NERC/NESC Compliance	-	-	-	-	-
	Contractor	-	-	-	-	-
	Labor	-	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
6	Substation Fall Protection	-	-	-	-	-
	Contractor	-	-	-	-	-
	Labor	-	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
7	Grid Technologies	-	-	-	-	-
	Contractor	-	-	-	-	-
	Labor	-	-	-	-	-
	Materials	-	-	-	-	-
	Business Expenses	-	-	-	-	-
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
8	**Total Capital**	8,669	8,358	2,090	10,448	8,542

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

Case No.: U-21870
Exhibit No.: A-119 (MPK-9)
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Witness: MPKelly
Date: June 2025

Line No	(a)	(b)	(c)	(d)	(e)	(f)
			Projected			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027	
9	Computer & Equipment	25	50	75	150	
	Contractor	-	-	-	-	
	Labor	-	-	-	-	
	Materials	-	-	-	-	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	25	50	75	150	
10	Tools	2,668	7,333	8,248	18,249	
	Contractor	62	170	191	422	
	Labor	-	-	-	-	
	Materials	2,606	7,163	8,057	17,827	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	-	-	-	-	
11	System Control Projects	93	279	219	591	
	Contractor	80	239	188	508	
	Labor	6	17	13	35	
	Materials	1	2	2	4	
	Business Expenses	0	0	0	1	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	7	20	16	43	
12	Facilities Security	-	-	-	-	
	Contractor	-	-	-	-	
	Labor	-	-	-	-	
	Materials	-	-	-	-	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	-	-	-	-	
13	NERC/NESC Compliance	-	-	-	-	
	Contractor	-	-	-	-	
	Labor	-	-	-	-	
	Materials	-	-	-	-	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	-	-	-	-	
14	Substation Fall Protection	-	-	-	-	
	Contractor	-	-	-	-	
	Labor	-	-	-	-	
	Materials	-	-	-	-	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	-	-	-	-	
15	Grid Technologies	-	-	-	-	
	Contractor	-	-	-	-	
	Labor	-	-	-	-	
	Materials	-	-	-	-	
	Business Expenses	-	-	-	-	
	Contingency	-	-	-	-	
	Other (Loadings, Chargebacks)	-	-	-	-	
16	**Total Capital**	2,786	7,662	8,542	18,990	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Wildfire Mitigation Program Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-21870
Exhibit No.: A-120 (MPK-10)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Wildfire Mitigation		-	-	-	-	-
	Contractor		-	-	-	-	-
	Labor		-	-	-	-	-
	Materials		-	-	-	-	-
	Business Expenses		-	-	-	-	-
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	-
2	Vulnerable Community		-	-	-	-	30,000
	Contractor		-	-	-	-	2,914
	Labor		-	-	-	-	3,984
	Materials		-	-	-	-	13,641
	Business Expenses		-	-	-	-	4
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	9,457
2	**Total Capital**		-	-	-	-	30,000

Line No	Description	Projected			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
3	Wildfire Mitigation	-	-	-	-
	Contractor	-	-	-	-
	Labor	-	-	-	-
	Materials	-	-	-	-
	Business Expenses	-	-	-	-
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
4	Vulnerable Community	-	-	30,000	30,000
	Contractor	-	-	2,914	2,914
	Labor	-	-	3,984	3,984
	Materials	-	-	13,641	13,641
	Business Expenses	-	-	4	4
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	9,457	9,457
4	**Total Capital**	-	-	30,000	30,000

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
IIJA Grant Funds Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-21870
Exhibit No.: A-121 (MPK-11)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ended 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	IIJA Grant					
	2024 Topic Area 1: 40101(c) Grid Reslience Program	-	-	(24,000)	(24,000)	(19,200)
	2024 40101(d) Formula Grants to States and Indian Tribes - Nottawaseppi Huron Band of the Potawatomi	-	(325)	(325)	(650)	(250)
	2024 40101(d) Formula Grants to States and Indian Tribes - Investment in DACs for Reliability and Readiness for Electrification		(675)	(675)	(1,349)	(2,698)
2	**Total Grant Funding**	-	(1,000)	(25,000)	(25,999)	(22,148)

Line No	Description	Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
3	IIJA Grant				
	2024 Topic Area 1: 40101(c) Grid Reslience Program	-	(24,000)	(19,200)	(43,200)
	2024 40101(d) Formula Grants to States and Indian Tribes - Nottawaseppi Huron Band of the Potawatomi	(108)	(542)	(250)	(900)
	2024 40101(d) Formula Grants to States and Indian Tribes - Investment in DACs for Reliability and Readiness for Electrification	(225)	(1,125)	(2,698)	(4,048)
4	**Total Capital**	(333)	(25,667)	(22,148)	(48,148)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric & Common O&M Expenses
Master
($000)

Case No.: U-21870
Exhibit No.: A-122 (MPK-12)
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Witness: MPKelly
Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 12 Mos Ended 12/31/2025	(d) Bridge Period 4 Mos Ending 4/30/2026	(e) 16 Mos Ending 4/30/2026	(f) Projected 12 Months Ending 4/30/2027
1	Electric Division Electric & Common O&M Expenses	**$ 246,620**	**$ 284,188**	**$ 98,126**	**$ 382,314**	**$ 300,994**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric & Common O&M Expenses
Operations and Engineering
($000)

Case No.: U-21870
Exhibit No.: A-123 (MPK-13)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 12 Mos Ended 12/31/2025	(d) Bridge Period 4 Mos Ending 4/30/2026	(e) 16 Mos Ending 4/30/2026	(f) Projected 12 Months Ending 4/30/2027
1	Electric Operations	$ 231,668	$ 264,093	$ 90,786	$ 354,879	$ 279,696
2	Electric Engineering Ops O&M	$ 14,953	$ 20,095	$ 7,339	$ 27,434	$ 21,298
3	**Total Electric & Common O&M Expenses**	**$ 246,620**	**$ 284,188**	**$ 98,126**	**$ 382,314**	**$ 300,994**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of 5yr Historical O&M Expenses
($000)

Case No.: U-21870
Exhibit No.: A-124 (MPK-14)
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Witness: MPKelly
Date: June 2025

Line No.	Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5-Year Average	12 Mos Ended 12/31/2025	Bridge Period 4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	Projected 12 Months Ending 4/30/2027	Test Year vs. 5-Year Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(i)	(j)	(k)	(l)	(m)
1	O&M Assoc w/Construction	(32)	(281)	(19)	(10)	(7)	(70)	-	-	-	-	70
2	Transformer Credits	0	-	-	-	-	0	-	-	-	-	(0)
3	**O&M Assoc w/Construction**	**(32)**	**(281)**	**(19)**	**(10)**	**(7)**	**(70)**	**-**	**-**	**-**	**-**	**70**
4	Lines Reliability - LVD	13	527	1,097	651	580	574	8,000	2,667	10,667	8,000	7,426
5	Lines Reliability - HVD	226	188	287	261	109	214	784	284	1,068	891	677
6	Substations Reliability - LVD	2,393	2,771	2,992	3,100	3,565	2,964	5,458	1,672	7,130	5,475	2,510
7	Substations Reliability - HVD	1,566	1,925	2,017	2,181	2,350	2,008	2,445	701	3,146	2,349	341
8	**Non-Forestry Reliability**	**4,198**	**5,410**	**6,394**	**6,193**	**6,603**	**5,760**	**16,688**	**5,324**	**22,012**	**16,715**	**10,955**
9	Lines Demand - HVD	527	784	1,086	654	898	790	2,237	875	3,113	2,979	2,189
10	Substations Demand - LVD	2,503	2,995	4,707	4,092	4,302	3,720	6,440	2,008	8,448	6,398	2,679
11	Substations Demand - HVD	2,308	2,986	3,159	3,383	4,050	3,177	5,309	1,703	7,012	5,311	2,134
12	Corrective Maintenance	4,064	4,535	4,131	4,130	4,615	4,295	4,970	1,631	6,601	5,236	941
13	Staking	3,035	3,251	3,587	3,975	6,148	3,999	12,260	3,870	16,131	13,948	9,949
14	Meter Services	8,288	8,635	9,635	11,559	11,165	9,856	12,625	5,420	18,045	17,088	7,232
15	Meter Credits	(9,408)	(6,545)	(8,772)	(15,493)	(9,391)	(9,922)	(9,445)	(3,980)	(13,426)	(10,257)	(335)
16	Streetlighting	1,680	2,109	1,801	1,571	1,612	1,755	2,009	733	2,742	2,089	334
17	Service Calls	3,871	4,518	4,110	4,434	4,194	4,225	4,632	1,805	6,438	5,699	1,474
18	Alma Equipment Repair	699	787	430	379	357	530	563	188	752	571	41
19	Meter Reading	1,439	1,740	1,712	6,016	1,645	2,510	1,876	627	2,503	1,971	(539)
20	Meter Tech & Mgmt Sys Support	934	1,019	1,085	1,199	1,063	1,060	1,310	448	1,758	1,393	333
21	Smart Energy MTC - Elec	8,846	8,986	9,020	8,756	9,611	9,044	9,226	3,096	12,322	9,226	182
22	**Ops, Mtc & Mtr w/o Svc Rest**	**28,786**	**35,798**	**35,693**	**34,655**	**40,269**	**35,040**	**54,012**	**18,425**	**72,438**	**61,652**	**26,612**
23	Service Restoration - LVD	71,262	159,659	113,271	188,041	156,098	137,666	159,737	54,606	214,344	165,215	27,548
24	**Service Restoration**	**71,262**	**159,659**	**113,271**	**188,041**	**156,098**	**137,666**	**159,737**	**54,606**	**214,344**	**165,215**	**27,548**
25	Training	5,366	10,807	10,993	12,076	11,107	10,070	15,072	5,492	20,564	15,833	5,763
26	Tools	1,422	2,358	1,753	1,384	1,256	1,634	1,497	997	2,494	1,982	348
27	Field Operations Expenses	1,665	2,372	2,194	2,369	2,154	2,151	2,509	869	3,378	2,608	457
28	Indirect Labor/Labor Variations	508	(552)	3,912	1,234	381	1,097	-	-	-	-	(1,097)
29	Supervision / Admin-Staff	5,047	4,994	6,366	3,710	3,672	4,758	4,820	1,734	6,555	5,312	554
30	Smart Energy Operations Center	430	-	-	-	-	86	-	-	-	-	(86)
31	Grid Management - Distr	3,768	6,363	6,134	5,514	4,646	5,285	4,741	1,439	6,180	4,271	(1,014)
32	HVD Lines Construction Workforce		-	-	-	-		-	-	-	-	-
33	Underground Workforce		128	172	327	713		1,113	694	1,807	2,236	2,236
34	**Field Operations**	**18,207**	**26,469**	**31,524**	**26,615**	**23,928**	**25,349**	**29,752**	**11,226**	**40,978**	**32,242**	**6,894**
35	Compliance and Controls	1,433	1,686	1,674	1,229	-	1,204	-	-	-	-	(1,204)
36	**Compliance and Controls**	**1,433**	**1,686**	**1,674**	**1,229**	**-**	**1,204**	**-**	**-**	**-**	**-**	**(1,204)**
37	Resource Planning & Closeout	204	-	-	-	-	41	-	-	-	-	(41)
38	Scheduling & Dispatch	4,053	-	-	-	-	811	-	-	-	-	(811)
39	Contract Administration	151	-	-	-	-	30	-	-	-	-	(30)
40	**Planning & Scheduling**	**4,407**	**-**	**-**	**-**	**-**	**881**	**-**	**-**	**-**	**-**	**(881)**
41	Work Management & Customer Delivery	1,315	4,027	6,799	3,910	2,290	3,668	1,883	635	2,518	1,917	(1,751)
42	OP Business Services			-	-	-	-	-	-	-	-	-
43	**Work Management & Customer Delivery**	**1,315**	**4,027**	**6,799**	**3,910**	**2,290**	**3,668**	**1,883**	**635**	**2,518**	**1,917**	**(1,751)**
44	**Operations Management**	**2,381**	**2,911**	**2,891**	**2,360**	**2,487**	**2,606**	**2,022**	**569**	**2,591**	**1,955**	**(651)**
45	**Ops IT Projects**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
46	**Total Electric Operations**	**131,957**	**235,680**	**198,228**	**262,994**	**231,668**	**212,105**	**264,093**	**90,786**	**354,879**	**279,696**	**68,103**
47	Engineering Support	-	-	-	719	1,000	344	1,227	414	1,642	1,277	933
48	Electric Distribution Management	-	-	117	227	124	93	167	56	224	174	81
49	Electric Distribution - LVD	5,768	6,818	8,629	7,291	7,254	7,152	11,007	4,268	15,276	11,773	4,621
50	Electric Distribution - HVD	7,310	6,481	6,397	5,567	6,131	6,377	6,909	2,367	9,276	7,199	822
51	Electric Distribution Strategy	-	65	662	147	444	264	465	67	532	363	99
53	Wildfire Mitigation Plan	-	-	-	-	-	-	319	167	486	512	512
54	**Electric Engineering Ops O&M**	**13,078**	**13,363**	**15,805**	**13,950**	**14,953**	**14,230**	**20,095**	**7,339**	**27,434**	**21,298**	**7,068**
55	**Total O&M**	**145,036**	**249,043**	**214,032**	**276,945**	**246,620**	**226,335**	**284,188**	**98,126**	**382,314**	**300,994**	**74,659**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric & Common O&M Expenses
O&M Programs Part 1
($000)

Case No.: U-21870
Exhibit No.: A-125 (MPK-15)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 12 Mos Ended 12/31/2025	(d) Bridge Period 4 Mos Ending 4/30/2026	(e) 16 Mos Ending 4/30/2026	(f) Projected 12 Months Ending 4/30/2027
1	O&M Assoc w/Construction	(7)	-	-	-	-
2	Transformer Credits	-	-	-	-	-
3	**O&M Assoc w/Construction**	**(7)**	**-**	**-**	**-**	**-**
4	Lines Reliability - LVD	580	8,000	2,667	10,667	8,000
5	Lines Reliability - HVD	109	784	284	1,068	891
6	Substations Reliability - LVD	3,565	5,458	1,672	7,130	5,475
7	Substations Reliability - HVD	2,350	2,445	701	3,146	2,349
8	**Non-Forestry Reliability**	**6,603**	**16,688**	**5,324**	**22,012**	**16,715**
9	Lines Demand - HVD	898	2,237	875	3,113	2,979
10	Substations Demand - LVD	4,302	6,440	2,008	8,448	6,398
11	Substations Demand - HVD	4,050	5,309	1,703	7,012	5,311
12	Corrective Maintenance	4,615	4,970	1,631	6,601	5,236
13	Staking	6,148	12,260	3,870	16,131	13,948
14	Meter Services	11,165	12,625	5,420	18,045	17,088
15	Meter Credits	(9,391)	(9,445)	(3,980)	(13,426)	(10,257)
16	Streetlighting	1,612	2,009	733	2,742	2,089
17	Service Calls	4,194	4,632	1,805	6,438	5,699
18	Alma Equipment Repair	357	563	188	752	571
19	Meter Reading	1,645	1,876	627	2,503	1,971
20	Meter Tech & Mgmt Sys Support	1,063	1,310	448	1,758	1,393
21	Smart Energy MTC - Elec	9,611	9,226	3,096	12,322	9,226
22	**Ops, Mtc & Mtr w/o Svc Rest**	**40,269**	**54,012**	**18,425**	**72,438**	**61,652**
23	Service Restoration - LVD	156,098	159,737	54,606	214,344	165,215
24	**Service Restoration**	**156,098**	**159,737**	**54,606**	**214,344**	**165,215**
25	Training	11,107	15,072	5,492	20,564	15,833
26	Tools	1,256	1,497	997	2,494	1,982
27	Field Operations Expenses	2,154	2,509	869	3,378	2,608
28	Indirect Labor/Labor Variations	381	-	-	-	-
29	Supervision / Admin-Staff	3,672	4,820	1,734	6,555	5,312
30	Smart Energy Operations Center	-	-	-	-	-
31	Grid Management - Distr	4,646	4,741	1,439	6,180	4,271
32	HVD Lines Construction Workforce	-	-	-	-	-
33	Underground Workforce	713	1,113	694	1,807	2,236
34	**Field Operations**	**23,928**	**29,752**	**11,226**	**40,978**	**32,242**
35	Compliance and Controls	-	-	-	-	-
36	**Compliance and Controls**	**-**	**-**	**-**	**-**	**-**
37	Resource Planning & Closeout	-	-	-	-	-
38	Scheduling & Dispatch	-	-	-	-	-
39	Contract Administration	-	-	-	-	-
40	**Planning & Scheduling**	**-**	**-**	**-**	**-**	**-**
41	Work Management & Customer Delivery	2,290	1,883	635	2,518	1,917
42	OP Business Services	-	-	-	-	-
43	**Work Management & Customer Delivery**	**2,290**	**1,883**	**635**	**2,518**	**1,917**
44	**Operations Management**	**2,487**	**2,022**	**569**	**2,591**	**1,955**
45	**Ops IT Projects**	**-**	**-**	**-**	**-**	**-**
46	**Total Electric Operations**	**231,668**	**264,093**	**90,786**	**354,879**	**279,696**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric & Common O&M Expenses
O&M Programs Part 2
($000)

Case No.: U-21870
Exhibit No.: A-126 (MPK-16)
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Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 12 Mos Ended 12/31/2025	(d) Bridge Period 4 Mos Ending 4/30/2026	(e) 16 Mos Ending 4/30/2026	(f) Projected 12 Months Ending 4/30/2027
1	Engineering Support	**1,000**	**1,227**	**414**	**1,642**	**1,277**
2	Electric Distribution Management	**124**	**167**	**56**	**224**	**174**
3	Electric Distribution - LVD	**7,254**	**11,007**	**4,268**	**15,276**	**11,773**
4	Electric Distribution - HVD	**6,131**	**6,909**	**2,367**	**9,276**	**7,199**
5	Electric Distribution Strategy	**444**	**465**	**67**	**532**	**363**
6	Wildfire Mitigation Plan	**-**	**319**	**167**	**486**	**512**
7	**Electric Engineering Ops O&M**	**14,953**	**20,095**	**7,339**	**27,434**	**21,298**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Cost Splits
($000)

Case No.: U-21870
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Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 12 Mos Ended 12/31/2025	(d) 4 Mos Ending 4/30/2026	(e) 16 Mos Ending 4/30/2026	(f) Projected 12 Months Ending 4/30/2027
1	**O&M Assoc w/Construction**	**-7**	**0**	**0**	**0**	**0**
	Labor	-1	0	0	0	0
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	-6	0	0	0	0
2	**Transformer Credits**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
3	**Lines Reliability - LVD**	**580**	**8,000**	**2,667**	**10,667**	**8,000**
	Labor	91	1,261	420	1,682	1,261
	Union Labor	398	5,489	1,830	7,319	5,489
	Material	74	1,016	339	1,355	1,016
	Contractor	-5	-62	-21	-83	-62
	Non-Labor Overheads	17	242	81	322	242
	Non-Labor Other	4	54	18	72	54
4	**Lines Reliability - HVD**	**109**	**784**	**284**	**1,068**	**891**
	Labor	3	22	8	30	25
	Union Labor	5	34	12	46	39
	Material	0	3	1	5	4
	Contractor	70	504	183	686	572
	Non-Labor Overheads	1	6	2	9	7
	Non-Labor Other	30	215	78	293	244
5	**Substations Reliability - LVD**	**3,565**	**5,458**	**1,672**	**7,130**	**5,475**
	Labor	667	1,021	313	1,334	1,024
	Union Labor	1,823	2,791	855	3,645	2,799
	Material	85	130	40	169	130
	Contractor	552	845	259	1,103	847
	Non-Labor Overheads	433	664	203	867	666
	Non-Labor Other	6	9	3	12	9
6	**Substations Reliability - HVD**	**2,350**	**2,445**	**701**	**3,146**	**2,349**
	Labor	435	453	130	583	435
	Union Labor	1,452	1,511	433	1,945	1,452
	Material	20	21	6	27	20
	Contractor	194	202	58	259	194
	Non-Labor Overheads	238	248	71	319	238
	Non-Labor Other	10	10	3	13	10
7	**Lines Demand - HVD**	**898**	**2,237**	**875**	**3,113**	**2,979**
	Labor	488	1,215	475	1,690	1,617
	Union Labor	84	209	82	291	279
	Material	107	268	105	372	356
	Contractor	763	1,901	744	2,645	2,532
	Non-Labor Overheads	11	27	11	38	36
	Non-Labor Other	-555	-1,383	-541	-1,924	-1,841
8	**Substations Demand - LVD**	**4,302**	**6,440**	**2,008**	**8,448**	**6,398**
	Labor	999	1,495	466	1,961	1,485
	Union Labor	2,363	3,537	1,103	4,640	3,514
	Material	331	495	154	649	492
	Contractor	192	288	90	377	286
	Non-Labor Overheads	387	579	181	760	575
	Non-Labor Other	31	46	14	60	46
9	**Substations Demand - HVD**	**4,050**	**5,309**	**1,703**	**7,012**	**5,311**
	Labor	714	936	300	1,237	937
	Union Labor	1,927	2,526	810	3,336	2,527
	Material	861	1,129	362	1,492	1,130
	Contractor	270	354	113	467	354
	Non-Labor Overheads	290	380	122	502	380
	Non-Labor Other	-13	-17	-5	-22	-17

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Cost Splits
($000)

Case No.: U-21870
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Line No.	Description	(a) 2024 Actual	(b) 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 16 Mos Ending 4/30/2026	(e) Projected 12 Months Ending 4/30/2027
10	**Corrective Maintenance**	**4,615**	**4,970**	**1,631**	**6,601**	**5,236**
	Labor	1,578	1,700	558	2,257	1,791
	Union Labor	2,659	2,864	940	3,803	3,017
	Material	-44	-47	-16	-63	-50
	Contractor	308	332	109	440	349
	Non-Labor Overheads	405	436	143	579	459
	Non-Labor Other	-291	-313	-103	-416	-330
11	**Staking**	**6,148**	**12,260**	**3,870**	**16,131**	**13,948**
	Labor	0	0	0	0	0
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	6,148	12,260	3,870	16,131	13,948
12	**Meter Services**	**11,165**	**12,625**	**5,420**	**18,045**	**17,088**
	Labor	6,639	7,507	3,223	10,730	10,161
	Union Labor	2,840	3,211	1,378	4,589	4,346
	Material	148	168	72	240	227
	Contractor	49	56	24	79	75
	Non-Labor Overheads	1,422	1,608	690	2,298	2,177
	Non-Labor Other	67	76	32	108	102
13	**Meter Credits**	**-9,391**	**-9,445**	**-3,980**	**-13,426**	**-10,257**
	Labor	0	0	0	0	0
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	-9,391	-9,445	-3,980	-13,426	-10,257
14	**Streetlighting**	**1,612**	**2,009**	**733**	**2,742**	**2,089**
	Labor	480	599	219	817	623
	Union Labor	565	705	257	962	733
	Material	92	115	42	157	120
	Contractor	376	468	171	639	487
	Non-Labor Overheads	92	115	42	157	120
	Non-Labor Other	6	7	3	10	7
15	**Service Calls**	**4,194**	**4,632**	**1,805**	**6,438**	**5,699**
	Labor	1,143	1,262	492	1,754	1,553
	Union Labor	2,655	2,932	1,143	4,075	3,608
	Material	267	295	115	410	363
	Contractor	576	636	248	884	783
	Non-Labor Overheads	378	418	163	581	514
	Non-Labor Other	-825	-912	-355	-1,267	-1,122
16	**Alma Equipment Repair**	**357**	**563**	**188**	**752**	**571**
	Labor	154	243	81	324	246
	Union Labor	265	419	140	559	425
	Material	57	89	30	119	91
	Contractor	-25	-39	-13	-52	-40
	Non-Labor Overheads	44	69	23	92	70
	Non-Labor Other	-138	-217	-73	-290	-220
17	**Meter Reading**	**1,645**	**1,876**	**627**	**2,503**	**1,971**
	Labor	1,296	1,478	494	1,973	1,553
	Union Labor	1	1	0	2	1
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	1	1	0	1	1
	Non-Labor Other	347	395	132	528	416
18	**Meter Tech & Mgmt Sys Support**	**1,063**	**1,310**	**448**	**1,758**	**1,393**
	Labor	614	757	259	1,016	805
	Union Labor	393	484	165	650	515
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	56	69	24	92	73
19	**Smart Energy MTC - Elec**	**9,611**	**9,226**	**3,096**	**12,322**	**9,226**
	Labor	0	0	0	0	0
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	523	502	169	671	502
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	9,088	8,724	2,928	11,651	8,724

MICHIGAN PUBLIC SERVICE COMMISSION
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($000)

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Line No.	Description	(a) 2024 Actual	(b) 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 16 Mos Ending 4/30/2026	(e) Projected 12 Months Ending 4/30/2027
20	**Service Restoration - LVD**	**156,098**	**159,737**	**54,606**	**214,344**	**165,215**
	Labor	50,885	52,072	17,801	69,873	53,857
	Union Labor	27,285	27,921	9,545	37,466	28,879
	Material	5,541	5,670	1,938	7,608	5,865
	Contractor	48,655	49,789	17,021	66,810	51,497
	Non-Labor Overheads	4,320	4,421	1,511	5,932	4,573
	Non-Labor Other	19,411	19,864	6,790	26,654	20,545
21	**Training**	**11,107**	**15,072**	**5,492**	**20,564**	**15,833**
	Labor	-1,809	-2,455	-894	-3,349	-2,579
	Union Labor	12,341	16,747	6,103	22,850	17,593
	Material	65	89	32	121	93
	Contractor	0	0	0	0	0
	Non-Labor Overheads	58	79	29	107	83
	Non-Labor Other	451	612	223	835	643
22	**Tools**	**1,256**	**1,497**	**997**	**2,494**	**1,982**
	Labor	147	175	117	292	232
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	1,108	1,321	880	2,202	1,750
23	**Field Operations Expenses**	**2,154**	**2,509**	**869**	**3,378**	**2,608**
	Labor	-9	-11	-4	-15	-11
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	2,163	2,519	873	3,392	2,619
24	**Indirect Labor/Labor Variations**	**381**	**0**	**0**	**0**	**0**
	Labor	-87,370	0	0	0	0
	Union Labor	87,722	0	0	0	0
	Material	1	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	11	0	0	0	0
	Non-Labor Other	18	0	0	0	0
25	**Supervision / Admin-Staff**	**3,672**	**4,820**	**1,734**	**6,555**	**5,312**
	Labor	3,052	4,007	1,442	5,448	4,415
	Union Labor	0	0	0	0	0
	Material	1	1	0	1	1
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	619	813	293	1,106	896
26	**Smart Energy Operations Center**	**0**	**0**	**0**	**0**	**0**
	Labor				0	
	Union Labor				0	
	Material				0	
	Contractor				0	
	Non-Labor Overheads				0	
	Non-Labor Other				0	
27	**Grid Management - Distr**	**4,646**	**4,741**	**1,439**	**6,180**	**4,271**
	Labor	4,392	4,481	1,360	5,841	4,036
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	12	12	4	16	11
	Non-Labor Overheads	12	12	4	16	11
	Non-Labor Other	231	235	71	307	212
28	**HVD Lines Construction Workforce**	**0**	**0**	**0**	**0**	**0**
	Labor				0	
	Union Labor				0	
	Material				0	
	Contractor				0	
	Non-Labor Overheads				0	
	Non-Labor Other				0	

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Line No.	Description	(a) 2024 Actual	(b) 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 16 Mos Ending 4/30/2026	(e) Projected 12 Months Ending 4/30/2027
29	**Underground Workforce**	**713**	**1,113**	**694**	**1,807**	**2,236**
	Labor	600	937	585	1,521	1,883
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	113	176	110	286	354
30	**Compliance and Controls**	**0**	**0**	**0**	**0**	**0**
	Labor	0			0	
	Union Labor	0			0	
	Material	0			0	
	Contractor	0			0	
	Non-Labor Overheads	0			0	
	Non-Labor Other	0			0	
31	**Resource Planning & Closeout**	**0**	**0**	**0**	**0**	**0**
	Labor	0			0	
	Union Labor	0			0	
	Material	0			0	
	Contractor	0			0	
	Non-Labor Overheads	0			0	
	Non-Labor Other	0			0	
32	**Scheduling & Dispatch**	**0**	**0**	**0**	**0**	**0**
	Labor	0			0	
	Union Labor	0			0	
	Material	0			0	
	Contractor	0			0	
	Non-Labor Overheads	0			0	
	Non-Labor Other	0			0	
33	**Contract Administration**	**0**	**0**	**0**	**0**	**0**
	Labor	0			0	
	Union Labor	0			0	
	Material	0			0	
	Contractor	0			0	
	Non-Labor Overheads	0			0	
	Non-Labor Other	0			0	
34	**Work Management & Customer Delivery**	**2,290**	**1,883**	**635**	**2,518**	**1,917**
	Labor	1,827	1,502	506	2,009	1,530
	Union Labor	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	463	381	128	509	388
35	**Operations Management**	**2,487**	**2,022**	**569**	**2,591**	**1,955**
	Labor	1,123	913	257	1,170	883
	Union Labor	0	0	0	0	0
	Material	794	645	182	827	624
	Contractor	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0
	Non-Labor Other	570	463	131	594	448
36	**Ops - IT Projects**	**0**	**0**	**0**	**0**	**0**
	Labor				0	
	Union Labor				0	
	Material				0	
	Contractor				0	
	Non-Labor Overheads				0	
	Non-Labor Other				0	

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Cost Splits
($000)

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Line No.	Description	(a)	(b) 2024 Actual	(c) 12 Mos Ended 12/31/2025	(d) 4 Mos Ending 4/30/2026	(e) 16 Mos Ending 4/30/2026	(f) Projected 12 Months Ending 4/30/2027
37	**Engineering Support**		**1,000**	**1,227**	**414**	**1,642**	**1,277**
	Labor		959	1,176	397	1,573	1,224
	Union Labor		0	0	0	0	0
	Material		0	0	0	0	0
	Contractor		0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0
	Non-Labor Other		42	51	17	68	53
38	**Electric Distribution Management**		**124**	**167**	**56**	**224**	**174**
	Labor		118	158	54	212	165
	Union Labor		0	0	0	0	0
	Material		2	2	1	3	2
	Contractor		0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0
	Non-Labor Other		5	6	2	9	7
39	**Electric Distribution - LVD**		**7,254**	**11,007**	**4,268**	**15,276**	**11,773**
	Labor		3,112	4,705	1,824	6,529	5,032
	Union Labor		96	145	56	201	155
	Material		97	147	57	204	157
	Contractor		41,383	62,559	24,256	86,815	66,907
	Non-Labor Overheads		114	172	67	239	184
	Non-Labor Other		-37,549	-56,720	-21,992	-78,712	-60,663
40	**Electric Distribution - HVD**		**6,131**	**6,909**	**2,367**	**9,276**	**7,199**
	Labor		3,219	3,628	1,243	4,871	3,780
	Union Labor		17	19	6	25	20
	Material		56	63	22	85	66
	Contractor		1,927	2,171	744	2,915	2,263
	Non-Labor Overheads		71	80	27	108	84
	Non-Labor Other		841	948	325	1,272	987
41	**Electric Distribution Strategy**		**444**	**465**	**67**	**532**	**363**
	Labor		149	156	22	178	122
	Union Labor		0	0	0	0	0
	Material		0	0	0	0	0
	Contractor		353	369	53	422	288
	Non-Labor Overheads		0	0	0	0	0
	Non-Labor Other		-57	-60	-9	-69	-47
42	**Wildfire Mitgation Plan**		**0**	**319**	**167**	**486**	**512**
	Labor		0	0	0	0	0
	Union Labor		0	0	0	0	0
	Material		0	0	0	0	0
	Contractor		0	319	167	486	512
	Non-Labor Overheads		0	0	0	0	0
	Non-Labor Other		0	0	0	0	0
43	**Total Electric Distribution O&M Expenses**		**$ 246,620**	**$ 284,188**	**$ 98,126**	**$ 382,314**	**$ 300,994**
	Labor		-4,306	91,392	32,147	123,539	98,085
	Union Labor		144,890	71,546	24,860	96,405	75,388
	Material		8,556	10,300	3,483	13,783	10,707
	Contractor		96,173	121,204	44,376	165,581	128,356
	Non-Labor Overheads		8,307	9,558	3,370	12,928	10,420
	Non-Labor Other		-7,000	-19,812	-10,110	-29,922	-21,962

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Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
($000)

Case No.: U-21870
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Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/2027	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**O&M Assoc w/Construction**	**-7**	**0**	**0**	**0**	**0**	**0**	**0**	**7**	**0**
	Labor	-1	0	0	0	0	0	0	1	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	-6	0	0	0	0	0	0	6	0
2	**Transformer Credits**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
3	**Lines Reliability - LVD**	**580**	**182**	**4**	**186**	**4**	**190**	**2**	**7,411**	**8,000**
	Labor	91	91	2	93	2	96	1	1,165	1,261
	Union Labor	398	0	0	0	0	0	0	5,091	5,489
	Material	74	74	2	75	2	77	1	939	1,016
	Contractor	-5	-5	0	-5	0	-5	0	-58	-62
	Non-Labor Overheads	17	17	0	18	0	18	0	223	242
	Non-Labor Other	4	4	0	4	0	4	0	50	54
4	**Lines Reliability - HVD**	**109**	**105**	**2**	**107**	**3**	**109**	**1**	**776**	**891**
	Labor	3	3	0	3	0	3	0	21	25
	Union Labor	5	0	0	0	0	0	0	34	39
	Material	0	0	0	0	0	0	0	3	4
	Contractor	70	70	1	72	2	73	1	498	572
	Non-Labor Overheads	1	1	0	1	0	1	0	6	7
	Non-Labor Other	30	30	1	31	1	31	0	213	244
5	**Substations Reliability - LVD**	**3,565**	**1,742**	**37**	**1,779**	**43**	**1,822**	**15**	**1,816**	**5,475**
	Labor	667	667	14	681	16	697	6	321	1,024
	Union Labor	1,823	0	0	0	0	0	0	976	2,799
	Material	85	85	2	86	2	89	1	41	130
	Contractor	552	552	12	563	14	577	5	266	847
	Non-Labor Overheads	433	433	9	442	11	453	4	209	666
	Non-Labor Other	6	6	0	6	0	6	0	3	9
6	**Substations Reliability - HVD**	**2,350**	**897**	**19**	**916**	**22**	**938**	**8**	**-49**	**2,349**
	Labor	435	435	9	444	11	455	4	-24	435
	Union Labor	1,452	0	0	0	0	0	0	0	1,452
	Material	20	20	0	21	1	21	0	-1	20
	Contractor	194	194	4	198	5	203	2	-10	194
	Non-Labor Overheads	238	238	5	243	6	249	2	-13	238
	Non-Labor Other	10	10	0	10	0	10	0	-1	10
7	**Lines Demand - HVD**	**898**	**814**	**17**	**832**	**20**	**851**	**7**	**2,037**	**2,979**
	Labor	488	488	10	498	12	510	4	1,103	1,617
	Union Labor	84	0	0	0	0	0	0	195	279
	Material	107	107	2	110	3	112	1	243	356
	Contractor	763	763	16	780	19	798	6	1,727	2,532
	Non-Labor Overheads	11	11	0	11	0	11	0	25	36
	Non-Labor Other	-555	-555	-12	-567	-14	-581	-5	-1,256	-1,841
8	**Substations Demand - LVD**	**4,302**	**1,939**	**41**	**1,980**	**48**	**2,028**	**16**	**1,991**	**6,398**
	Labor	999	999	21	1,020	24	1,044	8	433	1,485
	Union Labor	2,363	0	0	0	0	0	0	1,151	3,514
	Material	331	331	7	338	8	346	3	143	492
	Contractor	192	192	4	196	5	201	2	83	286
	Non-Labor Overheads	387	387	8	395	9	405	3	168	575
	Non-Labor Other	31	31	1	31	1	32	0	13	46

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Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/2027	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
9	**Substations Demand - HVD**	**4,050**	**2,123**	**45**	**2,167**	**52**	**2,219**	**18**	**1,147**	**5,311**
	Labor	714	714	15	729	17	747	6	184	937
	Union Labor	1,927	0	0	0	0	0	0	600	2,527
	Material	861	861	18	880	21	901	7	222	1,130
	Contractor	270	270	6	276	7	282	2	70	354
	Non-Labor Overheads	290	290	6	296	7	303	2	75	380
	Non-Labor Other	-13	-13	0	-13	0	-13	0	-3	-17
10	**Corrective Maintenance**	**4,615**	**1,956**	**41**	**1,997**	**48**	**2,045**	**16**	**515**	**5,236**
	Labor	1,578	1,578	33	1,611	39	1,650	13	127	1,791
	Union Labor	2,659	0	0	0	0	0	0	358	3,017
	Material	-44	-44	-1	-45	-1	-46	0	-4	-50
	Contractor	308	308	6	314	8	322	3	25	349
	Non-Labor Overheads	405	405	9	413	10	423	3	33	459
	Non-Labor Other	-291	-291	-6	-297	-7	-304	-2	-23	-330
11	**Staking**	**6,148**	**6,148**	**129**	**6,277**	**151**	**6,428**	**51**	**7,469**	**13,948**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	6,148	6,148	129	6,277	151	6,428	51	7,469	13,948
12	**Meter Services**	**11,165**	**8,326**	**175**	**8,500**	**204**	**8,704**	**70**	**5,474**	**17,088**
	Labor	6,639	6,639	139	6,779	163	6,941	56	3,164	10,161
	Union Labor	2,840	0	0	0	0	0	0	1,506	4,346
	Material	148	148	3	151	4	155	1	71	227
	Contractor	49	49	1	50	1	51	0	23	75
	Non-Labor Overheads	1,422	1,422	30	1,452	35	1,487	12	678	2,177
	Non-Labor Other	67	67	1	68	2	70	1	32	102
13	**Meter Credits**	**-9,391**	**-9,391**	**-197**	**-9,589**	**-230**	**-9,819**	**-79**	**-360**	**-10,257**
	Labor	0	0	0	0	0	0	0		0
	Union Labor	0	0	0	0	0	0	0		0
	Material	0	0	0	0	0	0	0		0
	Contractor	0	0	0	0	0	0	0		0
	Non-Labor Overheads	0	0	0	0	0	0	0		0
	Non-Labor Other	-9,391	-9,391	-197	-9,589	-230	-9,819	-79	-360	-10,257
14	**Streetlighting**	**1,612**	**1,046**	**22**	**1,068**	**26**	**1,094**	**9**	**421**	**2,089**
	Labor	480	480	10	490	12	502	4	116	623
	Union Labor	565	0	0	0	0	0	0	167	733
	Material	92	92	2	94	2	97	1	22	120
	Contractor	376	376	8	383	9	393	3	91	487
	Non-Labor Overheads	92	92	2	94	2	97	1	22	120
	Non-Labor Other	6	6	0	6	0	6	0	1	7
15	**Service Calls**	**4,194**	**1,539**	**32**	**1,571**	**38**	**1,609**	**13**	**1,423**	**5,699**
	Labor	1,143	1,143	24	1,167	28	1,195	10	349	1,553
	Union Labor	2,655	0	0	0	0	0	0	953	3,608
	Material	267	267	6	273	7	280	2	82	363
	Contractor	576	576	12	588	14	602	5	176	783
	Non-Labor Overheads	378	378	8	386	9	396	3	115	514
	Non-Labor Other	-825	-825	-17	-843	-20	-863	-7	-252	-1,122
16	**Alma Equipment Repair**	**357**	**92**	**2**	**93**	**2**	**96**	**1**	**209**	**571**
	Labor	154	154	3	157	4	161	1	84	246
	Union Labor	265	0	0	0	0	0	0	159	425
	Material	57	57	1	58	1	59	0	31	91
	Contractor	-25	-25	-1	-25	-1	-26	0	-14	-40
	Non-Labor Overheads	44	44	1	45	1	46	0	24	70
	Non-Labor Other	-138	-138	-3	-141	-3	-144	-1	-75	-220

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Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/2027	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
17	**Meter Reading**	**1,645**	**1,643**	**35**	**1,678**	**40**	**1,718**	**14**	**238**	**1,971**
	Labor	1,296	1,296	27	1,323	32	1,355	11	187	1,553
	Union Labor	1	0	0	0	0	0	0	0	1
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	1	1	0	1	0	1	0	0	1
	Non-Labor Other	347	347	7	354	8	362	3	50	416
18	**Meter Tech & Mgmt Sys Support**	**1,063**	**670**	**14**	**684**	**16**	**701**	**6**	**293**	**1,393**
	Labor	614	614	13	627	15	642	5	157	805
	Union Labor	393	0	0	0	0	0	0	122	515
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	56	56	1	57	1	58	0	14	73
19	**Smart Energy MTC - Elec**	**9,611**	**9,611**	**202**	**9,813**	**236**	**10,048**	**80**	**-903**	**9,226**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	523	523	11	534	13	547	4	-49	502
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	9,088	9,088	191	9,279	223	9,501	76	-854	8,724
20	**Service Restoration - LVD**	**156,098**	**128,813**	**2,705**	**131,518**	**3,156**	**134,675**	**1,077**	**2,178**	**165,215**
	Labor	50,885	50,885	1,069	51,954	1,247	53,201	426	231	53,857
	Union Labor	27,285	0	0	0	0	0	0	1,594	28,879
	Material	5,541	5,541	116	5,657	136	5,793	46	25	5,865
	Contractor	48,655	48,655	1,022	49,677	1,192	50,869	407	221	51,497
	Non-Labor Overheads	4,320	4,320	91	4,411	106	4,517	36	20	4,573
	Non-Labor Other	19,411	19,411	408	19,819	476	20,295	162	88	20,545
21	**Training**	**11,107**	**-1,235**	**-26**	**-1,261**	**-30**	**-1,291**	**-10**	**4,793**	**15,833**
	Labor	-1,809	-1,809	-38	-1,847	-44	-1,891	-15	-672	-2,579
	Union Labor	12,341	0	0	0	0	0	0	5,252	17,593
	Material	65	65	1	67	2	68	1	24	93
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	58	58	1	59	1	61	0	22	83
	Non-Labor Other	451	451	9	460	11	471	4	168	643
22	**Tools**	**1,256**	**1,256**	**26**	**1,282**	**31**	**1,313**	**11**	**659**	**1,982**
	Labor	147	147	3	150	4	154	1	77	232
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	1,108	1,108	23	1,132	27	1,159	9	582	1,750
23	**Field Operations Expenses**	**2,154**	**2,154**	**45**	**2,199**	**53**	**2,252**	**18**	**338**	**2,608**
	Labor	-9	-9	0	-9	0	-10	0	-1	-11
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	2,163	2,163	45	2,208	53	2,261	18	340	2,619
24	**Indirect Labor/Labor Variations**	**381**	**0**	**0**	**0**	**0**	**0**	**0**	**-381**	**0**
	Labor	-87,370	0	0	0	0	0	0	87,370	0
	Union Labor	87,722	0	0	0	0	0	0	-87,722	0
	Material	1	0	0	0	0	0	0	-1	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	11	0	0	0	0	0	0	-11	0
	Non-Labor Other	18	0	0	0	0	0	0	-18	0

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
25	**Supervision / Admin-Staff**	**3,672**	**3,672**	**77**	**3,749**	**90**	**3,839**	**31**	**1,443**	**5,312**
	Labor	3,052	3,052	64	3,116	75	3,191	26	1,199	4,415
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	1	1	0	1	0	1	0	0	1
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	619	619	13	632	15	648	5	243	896
26	**Smart Energy Operations Center**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
27	**Grid Management - Distr**	**4,646**	**4,646**	**98**	**4,744**	**114**	**4,858**	**39**	**-626**	**4,271**
	Labor	4,392	4,392	92	4,484	108	4,591	37	-592	4,036
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	12	12	0	12	0	13	0	-2	11
	Non-Labor Overheads	12	12	0	12	0	13	0	-2	11
	Non-Labor Other	231	231	5	236	6	241	2	-31	212
28	**HVD Lines Construction Workforce**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
29	**Underground Workforce**	**713**	**713**	**15**	**727**	**17**	**745**	**6**	**1,486**	**2,236**
	Labor	600	600	13	612	15	627	5	1,251	1,883
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	113	113	2	115	3	118	1	235	354
30	**Compliance and Controls**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
31	**Resource Planning & Closeout**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
32	**Scheduling & Dispatch**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
33	**Contract Administration**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
34	**Work Management & Customer Delivery**	**2,290**	**2,290**	**48**	**2,338**	**56**	**2,394**	**19**	**-496**	**1,917**
	Labor	1,827	1,827	38	1,865	45	1,910	15	-396	1,530
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	463	463	10	473	11	484	4	-100	388
35	**Operations Management**	**2,487**	**2,487**	**52**	**2,540**	**61**	**2,601**	**21**	**-666**	**1,955**
	Labor	1,123	1,123	24	1,147	28	1,174	9	-301	883
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	794	794	17	811	19	830	7	-213	624
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	570	570	12	582	14	596	5	-153	448
36	**Ops - IT Projects**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
37	**Engineering Support**	**1,000**	**1,000**	**21**	**1,021**	**25**	**1,046**	**8**	**223**	**1,277**
	Labor	959	959	20	979	23	1,003	8	214	1,224
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	42	42	1	42	1	43	0	9	53
38	**Electric Distribution Management**	**124**	**124**	**3**	**127**	**3**	**130**	**1**	**43**	**174**
	Labor	118	118	2	120	3	123	1	41	165
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	2	2	0	2	0	2	0	1	2
	Contractor	0	0	0	0	0	0	0	0	0
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	5	5	0	5	0	5	0	2	7
39	**Electric Distribution - LVD**	**7,254**	**7,158**	**150**	**7,308**	**175**	**7,483**	**60**	**4,134**	**11,773**
	Labor	3,112	3,112	65	3,177	76	3,254	26	1,752	5,032
	Union Labor	96	0	0	0	0	0	0	59	155
	Material	97	97	2	99	2	101	1	55	157
	Contractor	41,383	41,383	869	42,252	1,014	43,266	346	23,295	66,907
	Non-Labor Overheads	114	114	2	116	3	119	1	64	184
	Non-Labor Other	-37,549	-37,549	-789	-38,337	-920	-39,257	-314	-21,091	-60,663

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
($000)

Case No.: U-21870
Exhibit No.: A-128 (MPK-18)
Page: 6 of 6
Witness: MPKelly
Date: June 2025

Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/2027	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
40	**Electric Distribution - HVD**	**6,131**	**6,114**	**128**	**6,242**	**150**	**6,392**	**51**	**739**	**7,199**
	Labor	3,219	3,219	68	3,287	79	3,366	27	388	3,780
	Union Labor	17	0	0	0	0	0	0	3	20
	Material	56	56	1	57	1	59	0	7	66
	Contractor	1,927	1,927	40	1,967	47	2,014	16	232	2,263
	Non-Labor Overheads	71	71	1	73	2	74	1	9	84
	Non-Labor Other	841	841	18	859	21	879	7	101	987
41	**Electric Distribution Strategy**	**444**	**444**	**9**	**453**	**11**	**464**	**4**	**-105**	**363**
	Labor	149	149	3	152	4	155	1	-35	122
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	353	353	7	360	9	369	3	-83	288
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	-57	-57	-1	-58	-1	-60	0	14	-47
42	**Wildfire Mitgation Plan**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**512**	**512**
	Labor	0	0	0	0	0	0	0	0	0
	Union Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	0	0	0	0	0	0	0	512	512
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
43	**Total Electric Distribution O&M Expenses**	**$ 246,620**	**$ 189,078**	**$ 3,971**	**$ 193,048**	**$ 4,633**	**$ 197,682**	**$ 1,581**	**$ 44,188**	**$ 300,994**
	Labor	-4,306	83,065	1,744	84,810	2,035	86,845	695	97,916	98,085
	Union Labor	144,890	0	0	0	0	0	0	-69,502	75,388
	Material	8,556	8,555	180	8,735	210	8,945	72	1,690	10,707
	Contractor	96,173	96,173	2,020	98,193	2,357	100,549	804	27,003	128,356
	Non-Labor Overheads	8,307	8,296	174	8,470	203	8,673	69	1,666	10,420
	Non-Labor Other	-7,000	-7,012	-147	-7,159	-172	-7,331	-59	-14,585	-21,962

Notes

		2025	2026	2027
44	Annual merit increase			
	Annual merit increase	2.1%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated merit increase	2.1%	2.4%	0.8%
45	Annual inflation rates per Company witness Daly			
	Annual inflation rates	2.1%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.1%	2.4%	0.8%

Reliability Roadmap (2025-2029)

As Amended for Case No. U-21870

June 1, 2025

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Executive Summary

Consumers Energy Company ("Consumers Energy" or the "Company") is driven by its purpose to achieve world-class performance delivering hometown service, measured by a triple bottom line—people, planet, and Michigan's prosperity. The triple bottom line balances the interests of customers with other stakeholders, and captures the broader societal impacts of the Company's activities.

People – The Company's purpose and passion is to make life better for the people of Michigan. Consumers Energy is committed to providing safe, reliable, and affordable electric service to its customers, and dedicated to providing a great customer experience—what Company employees refer to as providing 'hometown service.'

Planet – Consumers Energy's ambitious *Clean Energy Plan* will lead to achieving net zero carbon emissions by 2040 by eliminating the use of coal, bringing additional renewable energy resources on to the system, and working with customers to use energy more efficiently.

Consumers Energy is proud to be a leader in the clean energy transformation here in Michigan and across the country, as we forge a path toward a more sustainable energy future.

Michigan's Prosperity – Consumers Energy is committed to helping Michigan and its communities grow and thrive. A prosperous Michigan cannot exist without financially healthy utilities that provide safe, reliable, affordable, and increasingly cleaner energy. The significant funding the Company receives each year from investors and lenders makes possible the electric system infrastructure replacements and enhancements that benefit customers and the state of Michigan. Ensuring Michigan's prosperity also includes investing in local communities and supporting local nonprofits in addition to helping Michigan businesses grow and create jobs.

The Company has proudly served Michigan families and businesses since 1886, with more than 1.9 million electric customers across the state today. Consumers is committed to providing an electric distribution system that delivers safe, reliable, clean, and affordable electricity to customers today and in the future. To do that, the Company must address infrastructure risk in the near-term while adapting to meet evolving customer expectations and technology advancements.

The Company's commitment requires a distribution strategy based on four customer-focused outcomes, as follows:

- **Safe** – The Company will continue to design and maintain its distribution system to ensure the safety and security of customers and employees is maintained and ultimately enhanced.
- **Reliable and Resilient** –To ensure system *reliability* during predictable weather variations under normal operating conditions, the Company will improve its capabilities and visibility to proactively operate the system and better manage power quality to provide customers with a grid that remains stable and available. To ensure system *resiliency* and performance, the Company will harden the system where necessary to withstand abnormal conditions driven by increasingly severe and unpredictable weather and climate events.
- **Clean and Equitable** – The Company is building a system that will be modernized, smart, and capable of accommodating changing customer technology adoption patterns (such as electric vehicles and distributed energy resources) for all communities served, ensuring members of disadvantaged communities have equitable opportunities to participate. The Company will deliver reliability and resiliency equitably across all communities.

- **Competitive** – Provide affordable rates that will create value for customers by attracting and retaining businesses that provide jobs and economic opportunities, while ensuring every community —especially our most vulnerable—sees maximum energy investment according to its needs with minimal impact and energy burden.

The Michigan Public Service Commission ("MPSC" or the "Commission") first directed the Company to submit a five-year electric distribution investment plan in Case No. U-17990 in 2017.

On March 1, 2018, the Company delivered its first *Electric Distribution Infrastructure Investment Plan* ("EDIIP"), meeting the MPSC's directive. The Company filed a second EDIIP on June 30, 2021. On September 8, 2022, in Case No. U-20147, the Commission directed Consumers Energy to file an updated EDIIP by September 29, 2023, and provided updated guidance on new and revised content for inclusion in the plan. That updated EDIIP was filed, and branded as the "Reliability Roadmap," a term we now use when referring to this document.

After the 2021 EDIIP was filed, the Company received feedback from stakeholders, customers, and the MPSC on what would make future distribution plans more useful and engaging. The Reliability Roadmap concisely describes how the Company is anticipating the future needs of customers, and is developing an enhanced distribution strategy, informed by industry best practices from around the nation, to deliver cost-effective reliability and resilience benefits.

Concurrent with the filing of its 2025 electric rate case (Case No. U-21870), the Company is filing this updated version of the Reliability Roadmap.

Highlights of the Reliability Roadmap

- **An Overview of Emerging Scenarios and How They Impact Planning**: In the coming years, the electric distribution system faces two substantial, externally driven changes: **increasingly severe weather tied to climate change**, and **technological advances that affect how customers manage their electricity usage**. To prepare for this future, the Company modeled three different risk scenarios and impacts to the grid from electric vehicles and heat pump adoption, as well as weather impacts from extreme heat, wind, and thunderstorms driven by climate change. Through this detailed modeling and analysis, the Company presents the future all Michiganders must prepare for, and the Company's plan to deliver a reliable and resilient energy grid that addresses these threats.
- **An Overview of the Company's Capital Project Planning Process**: The Company's multi-faceted planning **process prioritizes and sequences investments to meet system needs and deliver safe, reliable electric service to all customers and communities in its service territory.** The Reliability Roadmap details how the process maximizes customer benefits and ensures those benefits are equitable throughout Michigan. This process will be used to provide reliable and resilient power based on the future climate and technology adoption scenarios.
- **Asset Management Approaches for Distribution Assets**: In the Reliability Roadmap, the Company provides a **detailed overview of its distribution assets, including the system health of each asset group, the risks each group faces, and the proactive steps** the Company is taking to ensure they perform as intended. Asset subclasses are grouped based on whether they primarily ensure the reliability of the grid, resiliency of the grid, or the safety of the public and Company employees. The five-year investment plans for each asset, based on the need to address identified risks and deliver improved performance, are outlined in this report.

- **Additional Topics**: This section of the Reliability Roadmap particularly outlines technological and analytical innovations related to the distribution system, resource needs attached to the Roadmap, and distribution-related economic development proposals to help Michigan compete for prospective new large industrial customer facilities.

Throughout the updated Reliability Roadmap, the Company presents its vision for the electric distribution system, analyzed through the lens of the system's current state, and outlines an investment plan to bridge from the current state to the desired future state.

The Company fundamentally believes that the nearly $8 billion of total investments outlined in this plan will deliver the safety, reliability, and resiliency benefits that customers expect. The Company plans to seek recovery for these investments.

Timely recovery of the costs of the investments described in this plan is essential to delivering the desired improvements in performance. Projects will not be executed in a timely manner if cost recovery lags or is denied. This trimming of capital would result in lower customer benefits and a lower-performing system whereby the Company continues to deliver its customers 3rd to 4th quartile reliability.

The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is implemented and further improved over time. The Company plans to file updates to this plan, adding future years of investment and accounting for additional years of actual spending, with each subsequent rate case filing as an exhibit supporting test year investments.

A Note on Reliability Metrics

One of the important ways the Company measures how reliable we are delivering energy to our customers is to use the **System Average Interruption Duration Index ("SAIDI")**. The Federal Energy Regulatory Commission ("FERC") uses this reliability measure as do utilities to drive improvements in services. Originally developed by the Institute of Electrical and Electronics Engineers ("IEEE"), these metrics are significant and useful when evaluating and improving the quality of services delivered to customers.

The SAIDI Index has two components for measuring and reporting reliability:

1. The **System Average Interruption Frequency Index ("SAIFI")** tells us how frequently outages occur due to system condition, configuration, and related external conditions (e.g., weather patterns, forecasts, etc.). This measure is calculated by dividing the total number of customers interrupted by an outage by the total number of customers in the system.
    - Essentially, the SAIFI reveals *how often* the average customer has an interruption of power.
2. The **Customer Average Interruption Duration Index ("CAIDI")** tells us *how long* the interruptions last due to system conditions, resources available, number of interruptions, and storm restoration activities.
    - This measure is calculated by the total number of minutes customer energy is interrupted divided by the total number of customers whose service is interrupted.
    - CAIDI score reflects just the customers who were interrupted and measures the average time to restore services to those customers.

SAIDI results are calculated by multiplying **SAIFI** x **CAIDI**.

SAIDI is typically calculated excluding Major Event Days ("MEDs") to normalize performance data for unusually severe weather. The methodology for determining the level of storm activity to exclude in developing this chart is based on the *IEEE Guide for Electric Power Distribution Reliability Indices*[1].

However, the Company also tracks and reports its all-weather SAIDI, and discusses it at various points.

- The Company's SAIDI performance was 155 in the year 2024, which means the average amount of time a customer was without power that year was 155 minutes.

Understanding SAIDI is key to interpreting the Reliability Roadmap, which will quantify reliability in terms of SAIDI savings or outage minutes avoided because of specific investments.

As shown below in Figure 1, **Low Voltage Distribution** ("**LVD") Lines account for most of the Company's SAIDI minutes** due to the vast number of miles and territory served, exacerbated by its deterioration and exposure to trees and weather events. The Company's LVD system has 10 times more miles than its High Voltage Distribution ("HVD") system.

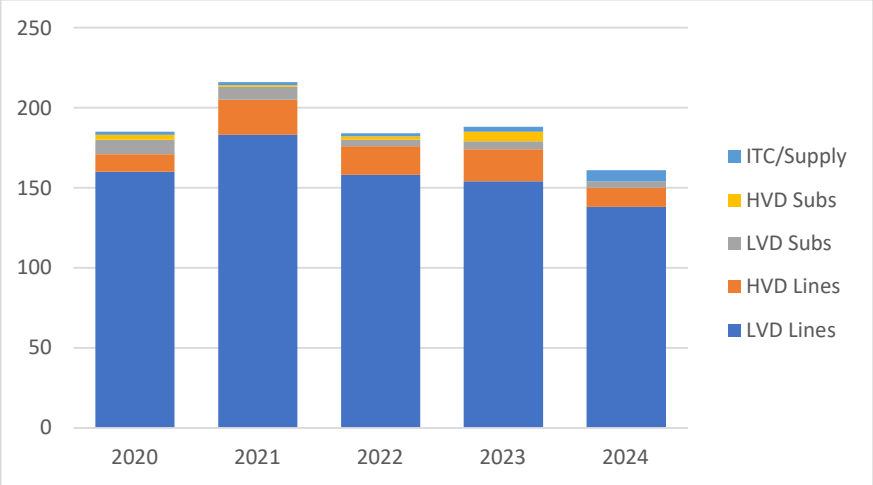
HVD Lines account for a smaller contribution to SAIDI—this is because SAIDI on HVD lines fell from 35.4 minutes in 2011 to just 12 minutes in 2024. This is attributable to increased investment in HVD assets over the last decade, in addition to the Company's aggressive and consistent *Forestry Line Clearing* program for HVD lines.

LVD and HVD substations account for a marginal amount of SAIDI minutes due to the redundancy built into the system, and maintenance and design choices that limit the probability of an outage. When substation failures do occur, the impact can affect tens of thousands of customers.

SAIDI minutes attributed to Michigan Electric Transmission Company ("METC"), the transmission provider (sometimes referred to by the name of METC's parent company **ITC**), also represent a minor amount of the overall SAIDI.

Figure 1

SAIDI MINUTES BY ASSET TYPE



[1] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily SAIDI values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

While the Reliability Roadmap accounts for growth in distributed energy resource penetration, the threats of extreme weather and existing system deterioration are too great to address through developing technologies.

Simply put, our customers and business need safe, affordable, and proven distribution assets to deliver the reliability we all deserve.

While distributed energy resources have an important role in the state's energy future, they are not the answer to achieving desired improvements in reliability and resiliency. To achieve the desired improvements in reliability and resiliency, the **Company must focus on hardening and improving the performance of its distribution system** through improving poles and wires.

- Effective increased investment in the LVD system is the key element needed to mitigate the worst effects of extreme weather and to begin to enable proactive planning for an increasingly electrified future.
- Enhancing the HVD system is also needed to maintain recent progress through proactively inspecting all assets repairing components on the HVD system to keep them within their useful lifecycle.

Vision for Our Grid

The Company is modernizing its electric distribution system to safely deliver clean, affordable, reliable power to customers throughout Michigan. **The goal is simple: fewer and shorter power outages for customers.** The vision for the grid is a blueprint for serving Michigan today and innovating to meet the challenges of the coming decades.

Customers depend on electricity to meet their everyday needs. They expect electricity to be delivered reliably on normal days with blue skies days under normal operating conditions, and the grid to be resilient in the face of increasingly extreme and unpredictable weather events.

Whether customers are using electricity to charge their electric vehicles, run their electric appliances, or are sending their on-site generation back to the grid, the Company must deliver reliable and resilient energy, and it is building the grid of the future to meet these customer needs.

Historic, once-in-a-lifetime storms are now the norm, resulting in more damaging storms that occur more frequently. The Company's analysis of weather patterns in recent years shows **that wind speeds and gusts continue to present a significant challenge for the distribution system**, as shown in Figures 9 and 10. While the Company is making an important transition in electric generation to address climate change and its impact on the weather, the same transformation is needed with the distribution system.

These risks will require a significant shift in our investment levels and strategy to mitigate the risks from extreme weather and improve the reliability of electric power.

In the face of these challenges, the Company has developed the Reliability Roadmap to respond to the immediate threats through proactive investments in automation, grid hardening, and aggressive maintenance and inspection of its system. This plan is the first step in developing the grid we expect, and lays out the scale of the challenges we face as a State.

The Reliability Roadmap, provided investment levels are fully approved, will serve as a bridge from our current grid to a grid that will be capable of achieving the following objectives:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities[2].**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

The Reliability Roadmap will significantly improve the Company's SAIDI performance over the next decade when compared to what would be delivered by recent electric rate case-approved levels of investment, providing a substantial improvement in performance over the Company's recent performance[3].

In the near term, the Company must address the timeworn infrastructure already on the system and proactively plan for increasingly severe weather.

- The Company is preparing to meet these challenges through increased inspections, preventative maintenance, and aggressive investment in hardening the grid through programs like strategic undergrounding and use of automated tools, such as automatic transfer recloser ("ATR") loops, to shorten the duration of outages.
- When storms do strike, the Company works to keep the public safe and uses all available tools to restore power as quickly as possible.

In the longer term, the grid will need capacity to meet customers' growing energy needs from electrification of transit, and other consumer products such as heat pumps and electrified appliances. With this growing dependance on the grid, the Company's focus on performance improvements will need to move beyond the traditional SAIDI excluding MED measurement to All-weather SAIDI. Measuring performance in all conditions will better represent our customers' experiences every day of the year, whether it is on a mild spring afternoon or after a sudden summer thunderstorm.

The deep electrification of the future will require investments to maintain reliable service and ensure every customer can power their homes, businesses, and vehicles.

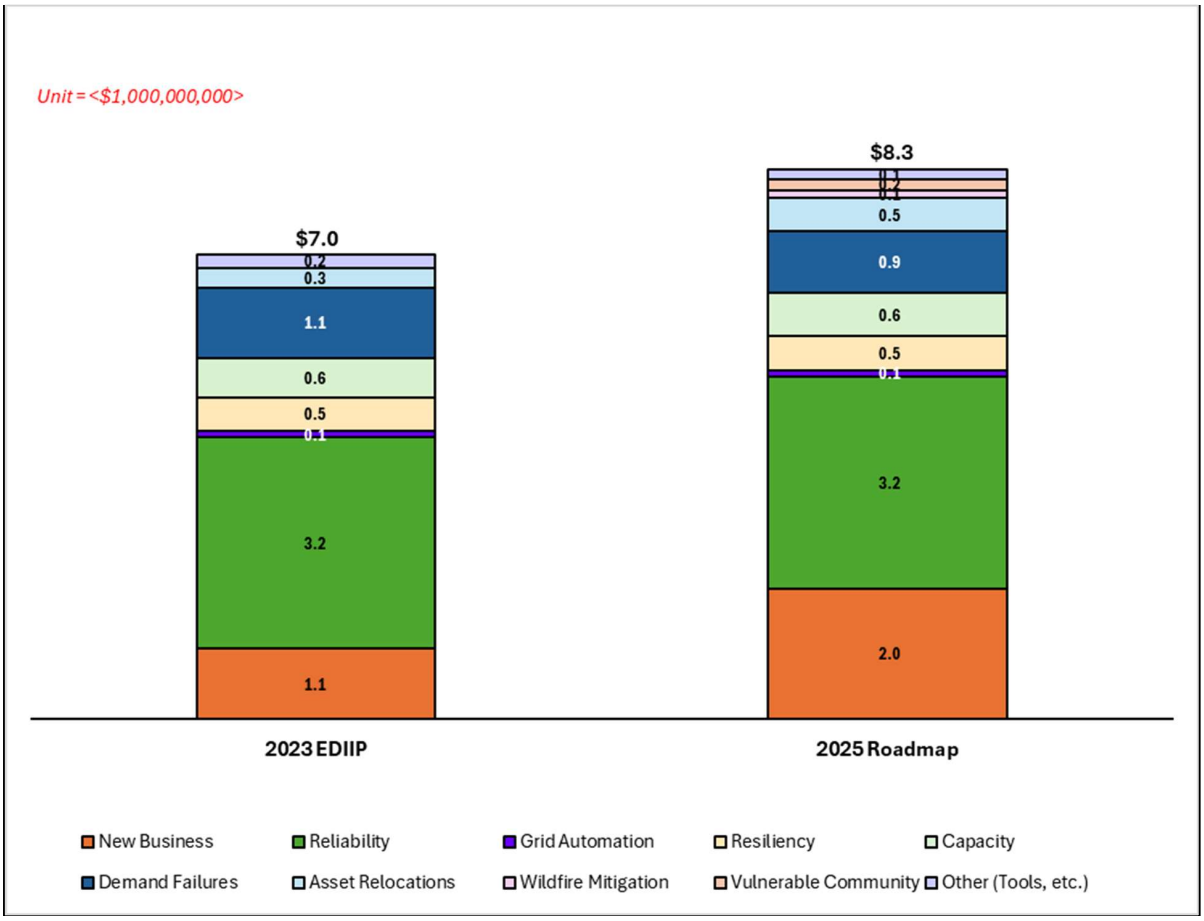
Investments in the next five years will total $8.3 billion—an increase of over $40 billion from what the Company outlined in its 2021 EDIIP. Operating and Maintenance ("O&M") increases to $2.5 billion over five years.

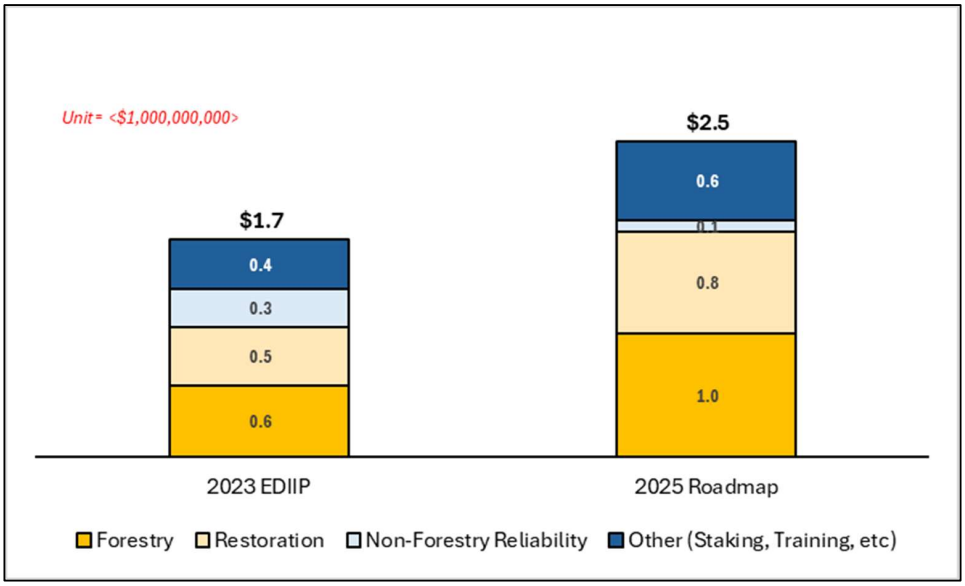
This investment is driven primarily by increased investments in Reliability, and to a smaller extent, by the Company's increased frequency of system inspections as well as the expectation that New Business, especially that tied to Economic Development, will continue to require investment in the system.

[2] 128 minutes for the 5-year average of IEEE Benchmark (2019-2023)
[3] 2018-2022 SAIDI excluding MED performance averaged 208 minutes

FIGURE 2

INVESTMENT FINANCIAL PLANS (2025-2029)





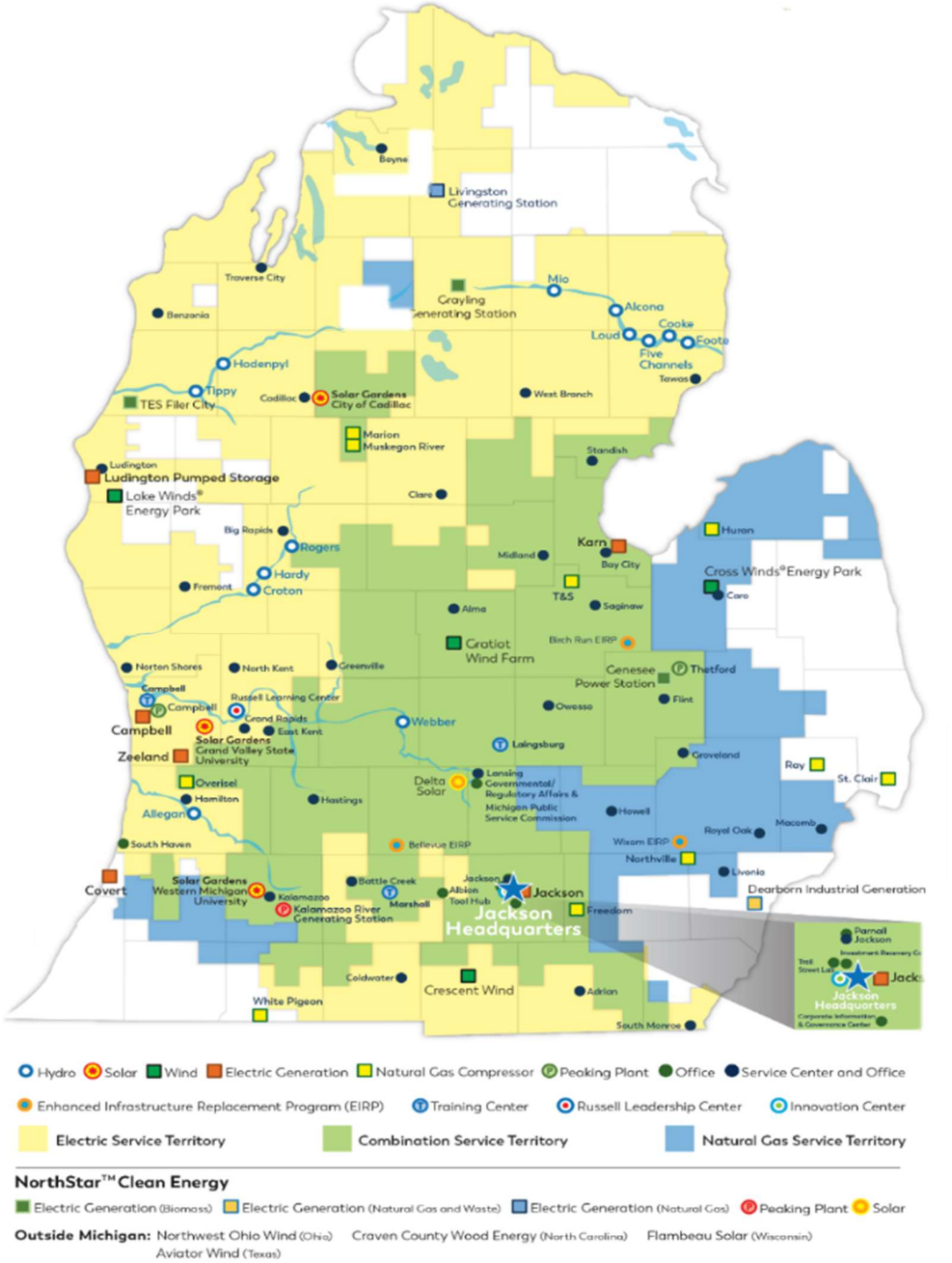
Distribution System Overview

Overview of Service Territory and System Components

The Company's electric distribution system is an essential part of Michigan's infrastructure, serving 1.9 million customers across more than 111,300 miles of distribution lines and 1,135 substations in the north, central, and western portions of Michigan from Monroe County to Mackinaw City, as shown in Figure 3.

FIGURE 3

CONSUMERS ENERGY SERVICE TERRITORY



The distribution system is functionally separated by operating voltage into HVD and LVD.

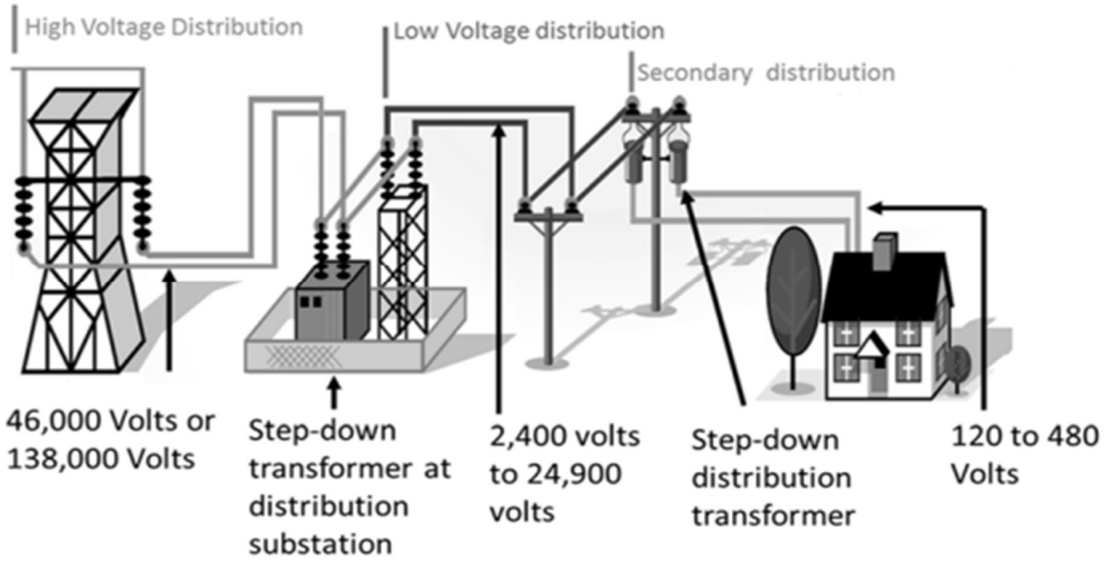
- **HVD operates at the highest voltages,** taking electricity from regional transmission companies, and transporting it across miles of lines, where it connects into the LVD system at 828 substations throughout the Company's service territory.
- **At LVD substations, high voltage is stepped down**, or reduced to lower voltages, onto the LVD system. LVD voltage is then further stepped down at secondary distribution transformers to secondary voltages (120 to 480 Volts), serving businesses and residences.

A *circuit* is a combination of electrical devices and hardware that are connected to and emanate from an LVD substation to deliver electricity to customers.

The Company's system has more than 2,000 LVD circuits.

- The primary distribution system begins at the distribution substation and ends at the distribution transformer.
- The secondary distribution system begins at the distribution transformer and ends at the customer, as shown below.

FIGURE 4
DISTRIBUTION SYSTEM COMPONENTS



LVD and Metro System

The LVD system is comprised of more than 107,000 total miles of lines, made up of approximately 61,000 miles of primary overhead and underground (carries electricity from substations to transformers), and 46,000 miles of secondary (carries electricity from distribution transformers to customers).

The LVD system consists of 13 different voltages. More detail on these assets and the Company's strategy for ensuring these assets operate as intended is described in more detail in the LVD Lines under the Overview of Asset Management section.

The LVD system also includes a distinct component called **the *Metropolitan Underground system (Metro)*, which provides underground distribution service** in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw.

- The Metro distribution infrastructure is installed underground to promote public safety by keeping energized infrastructure away from densely populated areas and protecting the aesthetics of downtown areas.
- The Company's Metro planning group focuses solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas.

More detail on the Metro assets and the Company's strategy for ensuring these assets operate as intended is described in more detail in the Metro chapter under the Overview of Asset Management section.

HVD System and Substations

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations.

It is composed of three distinct asset groups:

1. HVD substations
2. HVD lines
3. LVD substations, which are organized as part of the HVD system to leverage substation planning, engineering expertise, and large equipment resourcing in a consistent and efficient manner.

The Company's substation network consists of 1,135 substations.

- The HVD substation network consists of 144 HVD substations and 163 dedicated customer substations in addition to the LVD and general distribution substations mentioned earlier. Additionally, there are five Company-owned substations providing wholesale distribution services to rural co-op and municipal systems.
- Beyond the Company's substations, there are also 35 customer-owned dedicated substations, and 30 customer-owned substations providing wholesale distribution services to rural co-op and municipal systems. Although the Company does not own these, they are still connected to the Company's system.

More detail on these assets and the Company's strategy for ensuring they operate as intended is described in the HVD Lines and Substations chapters under the Overview of Asset Management section.

The HVD system is comprised of approximately 4,600 total miles, with about 4,400 of those miles being 46 kV and 69 kV overhead lines, and 19 miles being 46 kV underground lines, and approximately 200 miles being 138 kV overhead lines, and 4 miles being 138 kV underground lines.

System Condition

In accordance with the Commission's September 2022 Order in Case No. U-20147, the Company has benchmarked reliability performance against peer utilities, and the results of this are shown in Figure 5.

FIGURE 5

RELIABILITY BENCHMARKING AGAINST PEER UTILITIES



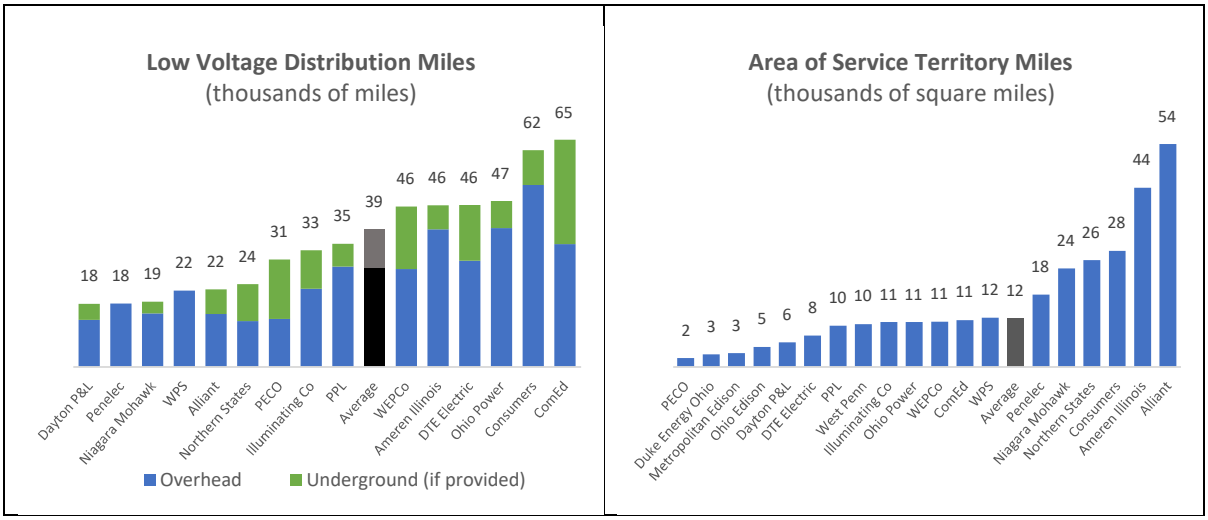
This benchmarking shows that, when normalized for capital investment per line mile, the Company provides average reliability, but outages tend to last longer than those of peers.

This long duration can, in part, be contributed to the size of the Company's service territory and the large number of overhead line miles used to serve its 1.9 million customers.

On average, the Company's employees maintain a system that is approximately 60% larger than its peers on both a line mile and 140% larger on a square mileage basis as depicted in Figure 6 below.

FIGURE 6

COMPARISON OF SERVICE TERRITORIES



The Company's service area has expanded to serve many new communities and businesses in Michigan throughout more than a century of distributing electricity. Much of this infrastructure—lines, poles, pole top equipment, and substations, among other assets—now needs replacement or upgrades to improve efficiency and reliability of the grid.

It is important to emphasize that age is *not* the only indicator of system health, nor is it the only driver of when an asset must be replaced—the pole shown below in Figure 7 is 86 years old and shows fewer reliability issues than some younger poles in the Company's service territory.

The Company thinks holistically about how to best serve customers reliably, and this means assets are replaced based on overall deterioration.

That said, age and deterioration are generally correlated, and the advanced age of many assets provides some indication of the general systemwide need for asset replacement.

Ultimately, the Company only replaces assets that are actually deteriorated based on inspection or performing poorly based on reliability data. The Company does not replace assets simply because of their age.

FIGURE 7
1936 VINTAGE 35-FOOT LVD POLE



The deterioration and health of assets vary based on field conditions (e.g., soil, weather, slope, wind patterns, etc.), location, and materials used by the manufacturer (e.g., wood type, porcelain, polymer, interrupting media, etc.). For example, poles deteriorate at a faster rate in wet soil conditions than in dry non-acidic soil conditions, and porcelain is more susceptible to freeze or thaw conditions than polymer.

The Company proactively replaces, rebuilds or rehabilitates assets before failure, when inspections or performance data indicate the asset is in a state of deterioration. Of course, when assets fail in the field and cause outages, the Company often replaces them as well, if doing so is more reasonable than fixing the broken asset.

Ultimately, the assets replaced, rebuilt or rehabilitated are done so to the specifications needed to meet future reliability and capacity needs of the grid.

The Company is enhancing its distribution asset management capabilities, as discussed in the Asset Investment Planning Optimization section, to address this issue.

Even as the Company's distribution asset management capabilities remain under development, the Company has developed new analytical approaches to assess system deterioration, particularly by using system performance data during adverse weather conditions.

Scenarios and Future Impacts to the Distribution System

Drivers of Change

Increasingly Severe Weather

The Great Lakes region is not immune to climate change; the Company has been monitoring the impacts of the changing climate and weather on its operations for years, and has been crafting an approach to remain resilient as new climate patterns emerge.

In 2022, the Company published its Climate Risk, Vulnerability and Resiliency report that identifies its susceptibility to the potential adverse effects of climate change, and discusses the Company's governance structures and proactive efforts to remain resilient to the potential impacts of climate change on its infrastructure.

The analysis completed through the development of this plan examines similar risks, including wind gusts, extreme heat, wildfires, and severe storms.

For much of history, the climate has gone through small changes, but the climate and associated weather patterns are now changing at an accelerated rate.

In recent years, the Company has experienced repeated instances of strong winds causing large-scale outages; since 2015, the Company has seen a general increase in the number of MEDs per year, as shown in Figure 8 below.

FIGURE 8
MAJOR EVENT DAYS BY YEAR

Year	MED Days
2015	3
2016	5
2017	8
2018	7
2019	9
2020	8
2021	11
2022	9
2023	11
2024	10

In general, the Company's service territory has experienced increased high and sustained wind speeds as well as wind gusts.

The Company monitors wind speed data from many National Weather Service stations throughout its service territory. Figures 9 and 10 below illustrate the hours each year of sustained high wind speeds and of high wind gusts.

FIGURE 9

STATION HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS

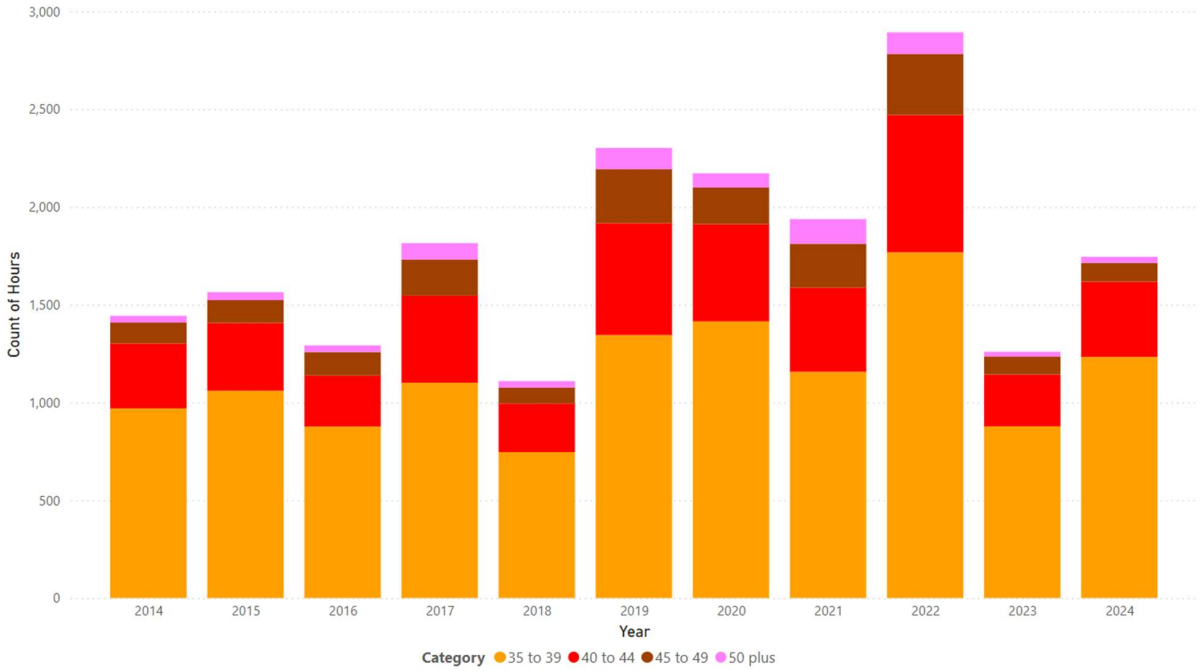
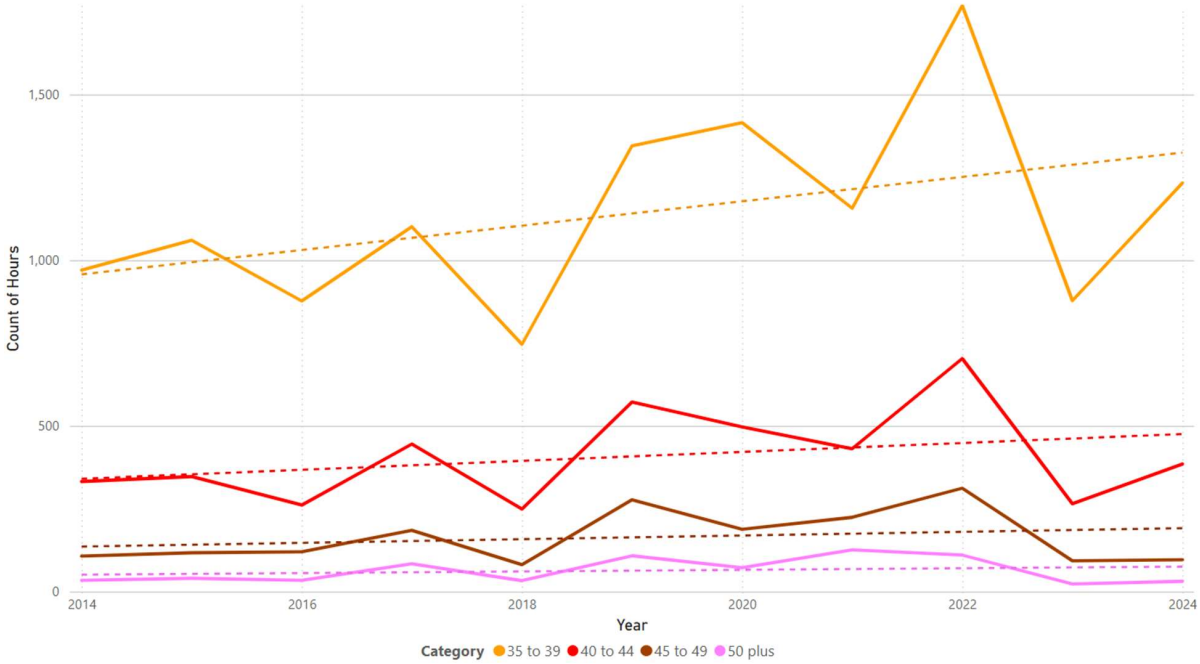


FIGURE 10

STATION HOURS EXCEEDING HIGH GUST THRESHOLDS



The number of large-scale storm outages, while increasing, is still consistent with normal weather variability. However, those severe weather events are likely to become more frequent as climate change increases the frequency of storms that cause high winds.

Climate change will also increase the frequency of extreme heat conditions, which tend to increase loading on the grid as customers use more air conditioning.

In assessing its investment plans, the Company is considering the likely resiliency risks from more frequent severe weather conditions, and what investments are needed to harden against those risks.

The Company is also considering how to best plan for increased load on circuits as rising temperatures result in more cooling degree days.

Technological Innovation

In the future, climate policies and targets related to decarbonization will likely lead to increased adoption of technologies that *will require* more electricity, although to date these new technologies have not experienced widespread penetration in the Company's electric service territory:

- Solar distributed generation ("DG") has an installed capacity of 135 MW across all customer types[4].
- Electric Vehicles ("EVs") currently represent less than 1% of total vehicles.
- Electric heat pumps have been adopted by 2% of total households.

Going forward, the Company expects increased adoption of these technologies, driving load growth that will have wide-ranging impacts for the distribution system.

In assessing its investment plans, the Company is considering whether individual circuits can accommodate rising peak demands, and whether they can accommodate increasing amounts of solar DG. This will inform the need for standard capacity improvements on the system but may also point to increased use of non-wire solutions to shave peak load or Distributed Energy Resource ("DER") management to interface with solar DG.

Scenario Analysis

As outlined in the previous section, the Company has identified severe weather and technological adoptions as the primary drivers of change on the distribution system, representing the most pressing challenges to the future grid.

To further refine this broad assessment of threats to grid reliability, the Company pursued a detailed analysis to predict the circuit-level impacts from severe weather and customer technology adoption.

Beginning in 2022, the Company developed a strategy to develop a resilient and reliability grid. This included creating a comprehensive vision of the future of the grid and ensuring near-term investments meet the needs and mitigate the risks anticipated in the future. This process sought to answer two key questions:

- What is the holistic set of challenges that the future grid must address?
- What are the most significant potential grid impacts?

[4] See the Company's Form EIA-861 filing.

Key Impacts Modeled

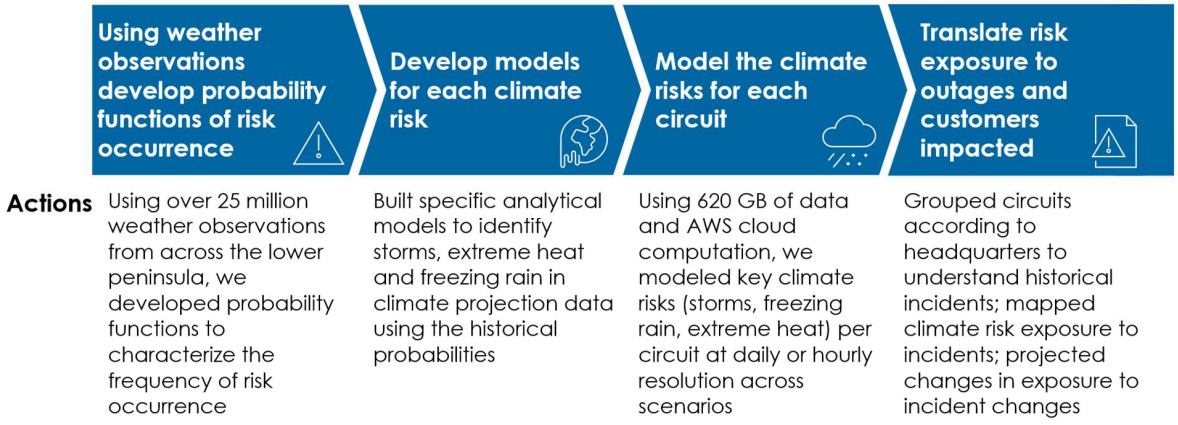
The impact of the two key drivers (climate risks and customer technology adoption) were modeled on the distribution grid.

- **Climate risks** included the highest-impact hazards for the Company's service territory: storm conditions, ice conditions, and extreme heat.
- **Customer technology adoption** included the impacts to the grid from projected solar distributed generation, heat pumps, and electric vehicles as well as organic load growth driven by population changes.

A climate model was used to identify climate risks specific to the Company's service territory and translates exposure to outages as detailed in Figure 11 below.

This model used more than 25 million weather observations from across the lower peninsula of Michigan to develop probabilities of the frequency of risk occurrence. These models predict the specific climate risks to individual circuits and translate the impact of these risks in terms of outages and customers impacted.

FIGURE 11
CLIMATE MODEL METHODOLOGY[5]

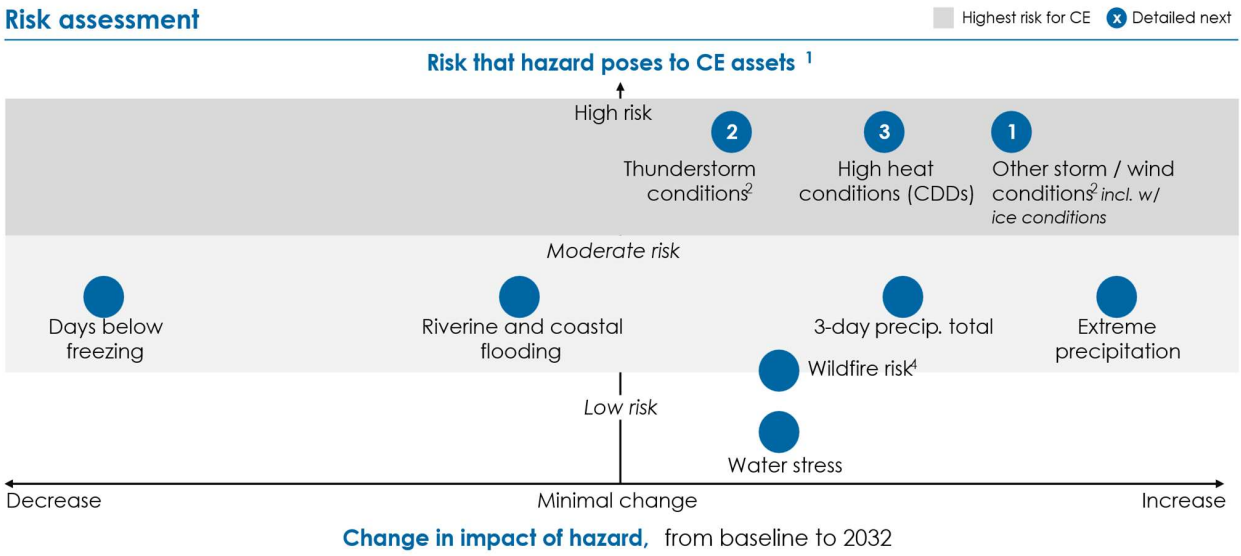


After evaluating numerous weather-related hazards shown in Figure 12 below, the modeling focused on the highest-impact hazards to Company assets and grid integrity including:

- **Thunderstorm conditions**, featuring extreme wind and precipitation, can impact tree and pole stability and often lead to outages. These storms are fueled by warm air and are thus most frequently observed in summer months.
- **Other storm conditions**, featuring extreme wind and precipitation, including in some cases the potential for damaging icing and freezing rain. Like thunderstorms, these storms can impact tree and pole stability, leading to outages but are observed year-round.
- **High heat conditions** defined as days above 86 degrees Fahrenheit, which may simultaneously increase customer demand and reduce the efficiency of the distribution grid (e.g., line losses).

[5] Climate and Technical Adoption modeling was performed by an independent third-party consultant.

FIGURE 12
CLIMATE RISKS EVALUATED



1. The risk to CE assets was determined subjectively based on whether direct asset damage was likely to occur at CE asset locations for that specific hazard and if so, would the damage be disruptive
2. Storm conditions are based on the precipitation, wind and temperature conditions of declared storms. Winter storms included conditions
3. Ice conditions refer to the proxy for freezing rain conditions based on extreme heat and extreme precipitation increases storms are captured under Storm / wind conditions.
4. The risk of wildfires in Michigan is not zero, but it is relatively lower than many other states such as California.

While other risks (e.g., riverine flooding) are present, their more limited spatial footprint makes them less likely to drive frequent widespread outages.

Emergent risks, such as wildfires, and extreme precipitation were analyzed in this modeling and deemed less of an immediate risk to Company assets compared to the three modeled risks.

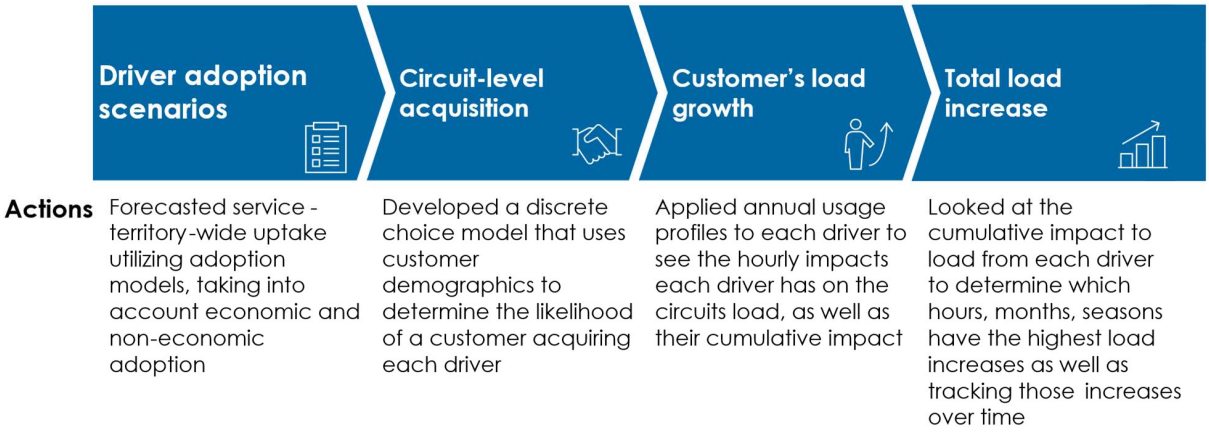
However, events like the June 2023 fire in Northern Michigan; the August 2023 wildfire in Maui; and other fires since then in the U.S. illustrate the need to more proactively address wildfire risk and mitigate that risk. **As a result, the Company developed a wildfire risk mitigation plan in 2024, discussed later in this report.**

In addition to climate modeling, the modeling also analyzed **the impact of new technology** adoption such as solar DG, EVs, and heat pumps, and how they will impact electric demand and corresponding grid capacity needs.

- The modeling forecasted the uptake of these new technologies to develop a discrete choice model based on customer demographics to **determine customer likelihood of acquiring these technologies** on each circuit and their usage profiles as detailed in Figure 13 below.
- With these two factors developed, the modeling calculated total load increase on the grid for each driver to determine which hours, months, and seasons have the highest load increases and how the increases evolve over time.

FIGURE 13

TECHNOLOGY ADOPTION MODEL METHODOLOGY



Identified Scenarios

The Company identified three scenarios governing the future through 2050. Each scenario assumes a given set of external trends encompassing both the rate of climate change and the rate of customer adoption of solar DG, electric heat pumps, and EVs.

The three scenarios are referred to as *Decelerated Transition* ("DT"), *Continued Momentum* ("CM"), and *Accelerated Transition* ("AT").

Federal policy, particularly as defined in the *Inflation Reduction Act of 2022* ("IRA"), makes a clear connection between the deployment and uptake of low-carbon technologies and achieving certain climate change targets. Correspondingly, these scenarios assume that uptake of low-carbon technologies will have a direct correlation with climate change outcomes.

In general, climate change will result in more severe weather and extreme heat, which creates increased reliability and resiliency challenges for the distribution system. Increased adoption of low-carbon technologies can also increase demand on the grid, at least in certain locations, which can also impact what investments are needed.

1. Decelerated Transition Scenario

The DT scenario assumes existing government climate policies, and other climate-related targets, are not fully implemented, and public action to mitigate climate risks slows down from current levels or even begins to reverse.

- In this scenario, uptake of low-carbon technologies is significantly delayed, with penetration levels remaining low overall. This scenario results in a temperature increase of ~2.5°C by 2050 compared to pre-industrial levels, with attendant increases in severe weather.

The Company's analysis generally assumes the DT scenario is the least likely, given the direction of climate policy and climate-related targets, although the Company has considered the impacts of this scenario to establish a worst-case baseline and conducted little analysis on it due to its improbability.

2. Continued Momentum Scenario

The CM scenario assumes climate policies already existing in law are fully executed, but that no new policies are implemented.

- In this scenario, public adoption of solar DG, heat pumps, and EVs broadly continue in their current post-IRA trends. This scenario results in a temperature increase of ~2.0°C by 2050 compared to pre-industrial levels; such a temperature increase still results in increased severe weather and increased resiliency risks to the grid, albeit not as large as under the DT scenario.
- The CM scenario makes further assumptions about electrification and decarbonization nationwide or worldwide. In particular, the CM scenario assumes the U.S. power grid becomes 80%-90% decarbonized by the late 2030s; that at least some heavy industry is deeply decarbonized in developed countries; that carbon capture and sequestration remains marginal; and that the U.S. and other developed economies transition to EV-majority vehicle sales during the period from 2030 to 2040.

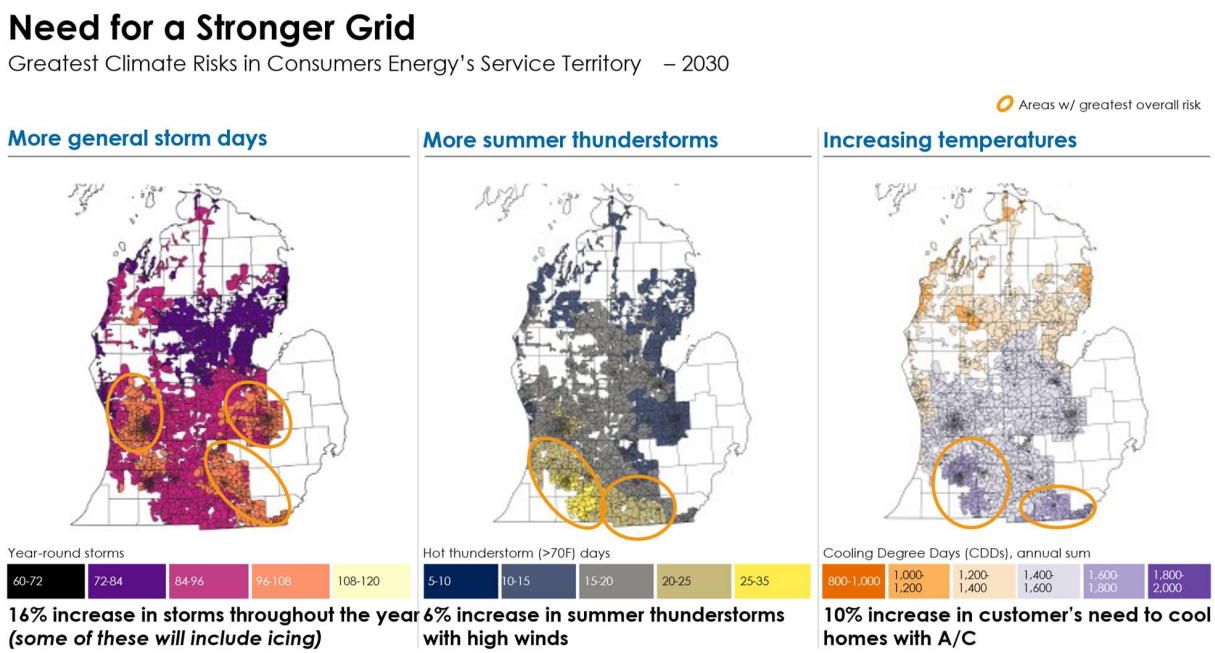
Without mitigation, the CM scenario projects that the Company's system would experience a 12% increase in the number of MED outages by 2030, and a 24% increase by 2050, due to increasingly severe weather.

Further, while the CM scenario only projects that 2% of the Company's circuits would be at risk of exceeding load constraints by 2030, this increases to 32% of circuits by 2050 as low-carbon technological penetration increases.

These increasing risks under the CM scenario are illustrated by the following maps that represent the projected situation in 2030, including where each risk is most acute.

FIGURE 14

CLIMATE RISK IN CONSUMERS ENERGY SERVICE TERRITORY



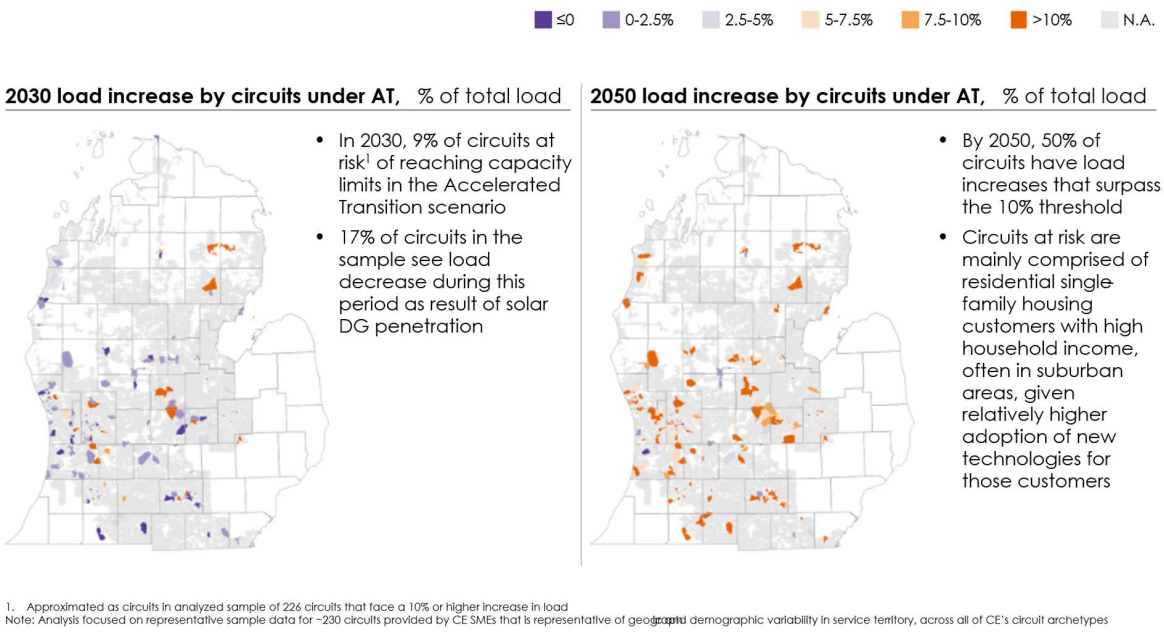
3. Accelerated Transition Scenario

The AT scenario assumes that, due to faster cost declines and increased financial incentives, solar DG and EVs are adopted even faster than on current trends, although heat pump adoption will remain stable as natural gas remains inexpensive in Michigan.

- In this scenario, temperatures increase by ~1.5°C by 2050 compared to pre-industrial levels, in line with targets set in the 2015 Paris Agreement and compatible with achieving global net-zero carbon dioxide emissions by 2050. This scenario minimizes the increased resiliency risk to the grid due to increasing severe weather, although there will still be increased resiliency risk compared to today.
- Like the CM scenario, the AT scenario makes several further assumptions about electrification and decarbonization nationwide and worldwide. The AT scenario assumes the U.S. power grid is fully decarbonized by 2035, and the global power system by 2040. It also assumes 90% of heavy industry is low emissions by 2050; that carbon capture and sequestration becomes widespread; and that no internal combustion cars are sold anywhere in the world after 2035.
- The AT scenario includes the greatest increase in risk of circuit overloads due to adoption of low-carbon technology. Under this scenario, by 2030 9% of circuits will face this risk based on a representative sample of over 10% of the Company's circuits. This risk only compounds after 2030, and by 2050 would apply to 50% of the Company's circuits.

FIGURE 15

ACCELERATED TRANSITION LOAD INCREASES



1. Approximated as circuits in analyzed sample of 226 circuits that face a 10% or higher increase in load
Note: Analysis focused on representative sample data for ~230 circuits provided by CE SMEs that is representative of geographic and demographic variability in service territory, across all of CE's circuit archetypes

Of these scenarios, the Company chose CM and AT scenarios for further analysis given their closer alignment to likely post-IRA pathways. As a significant fall below CM, DT was viewed as an unlikely worst-case scenario for heightened climate risk. For prioritized scenarios, load impacts of solar DG, heat pumps, and EVs were considered alongside organic load growth.

Impacts of Scenarios on the Distribution System

The modeled evolution of climate risks and customer technology adoption, and their impacts at an individual distribution circuit level, present the following types of grid challenges to the Company's distribution system:

1. **While there is long-term uncertainty around the pace of emissions and climate change, there is more near-term certainty around increases in warming and weather hazards.** In short, **climate change represents the most urgent threat** to the reliability of the Company's distribution system and must be addressed immediately.
2. **Without shifts in the Company's current investment strategy, outages from severe weather are likely to increase 10-15% relative to 2020 levels by the early 2030s regardless of climate policy actions**. In assessing its investment plans, the Company is considering the likely resiliency risks from more frequent strong wind and storms, and what investments are needed to harden against those risks.
3. **The largest relative increase in other storm (non-thunderstorm) days is likely to be in the winter** when outages are typically most difficult to restore.
4. **Depending on the trajectory of EV, heat pump, and solar DG adoption, the Company could see up to 1-10% of circuits reach at risk load levels by 2030[6].** By 2050, as many as 40% of circuits could see load more than 10% higher than current peaks.
5. **The long-term future of Michigan's energy system is a more electrified and distributed one.** There is uncertainty, however, over the pace at which this will occur, and therefore when challenges associated with peak loads and DER adoption will materialize. Understanding the pace of customer technology adoption will be critical for pre-empting peak demand challenges.
6. **With heightened heat pump adoption, there's the potential for Consumers Energy to shift from a summer to a winter peaking system.** The expected increase in winter load has implications for broader network design and planning (e.g., generation, equipment standards, etc.)

Challenges from Climate Risks

The magnitude of climate risk impacts likely to be seen in the Company's service territory represents a significant step-up from current levels as detailed in Figure 16 below.

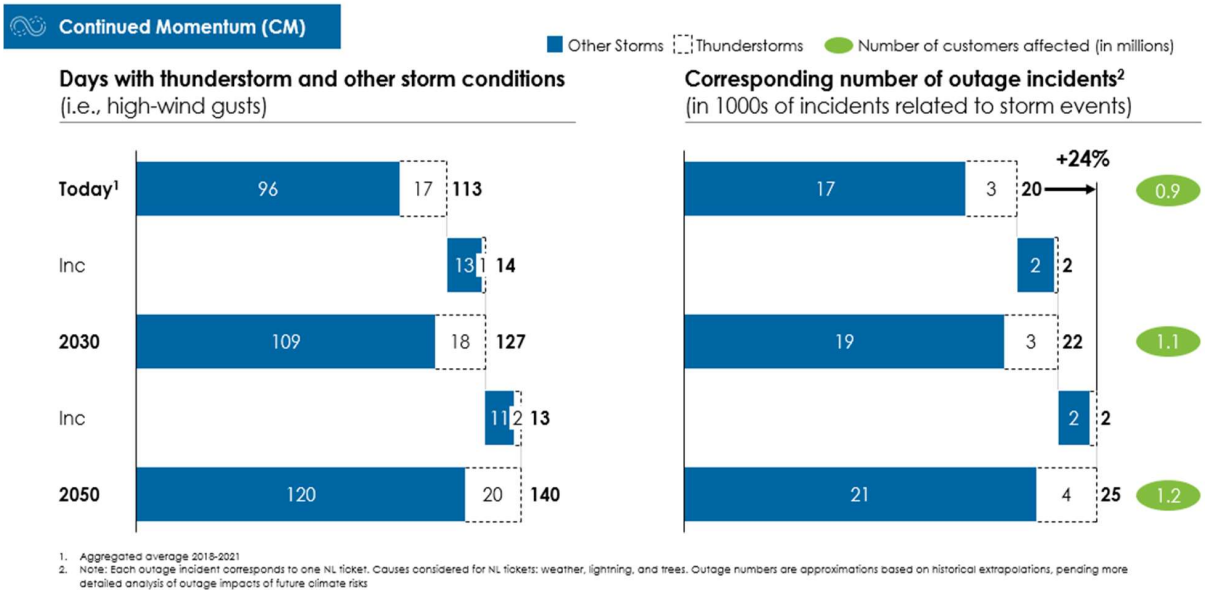
Key climate risks—storms with extreme wind, as well as high heat conditions—are projected to increase in the Company's service territory by up to 25% (20 storm days by 2030), and up to 45% (30 days by 2050).

These changes in climate conditions will compound with weather effects the Company has already seen over the last 15 years, such as a 9% or 7-day increase in storms and could lead to a 12% increase in the number of MED outages by 2030, absent countermeasures.

[6] Defined as increases more than 10% higher than current peak load, a typical threshold evaluated by CE.

Figure 16

PROJECTED DAYS WITH THUNDERSTORMS AND NUMBER OF OUTAGE INCIDENTS UNDER CONTINUED MOMENTUM

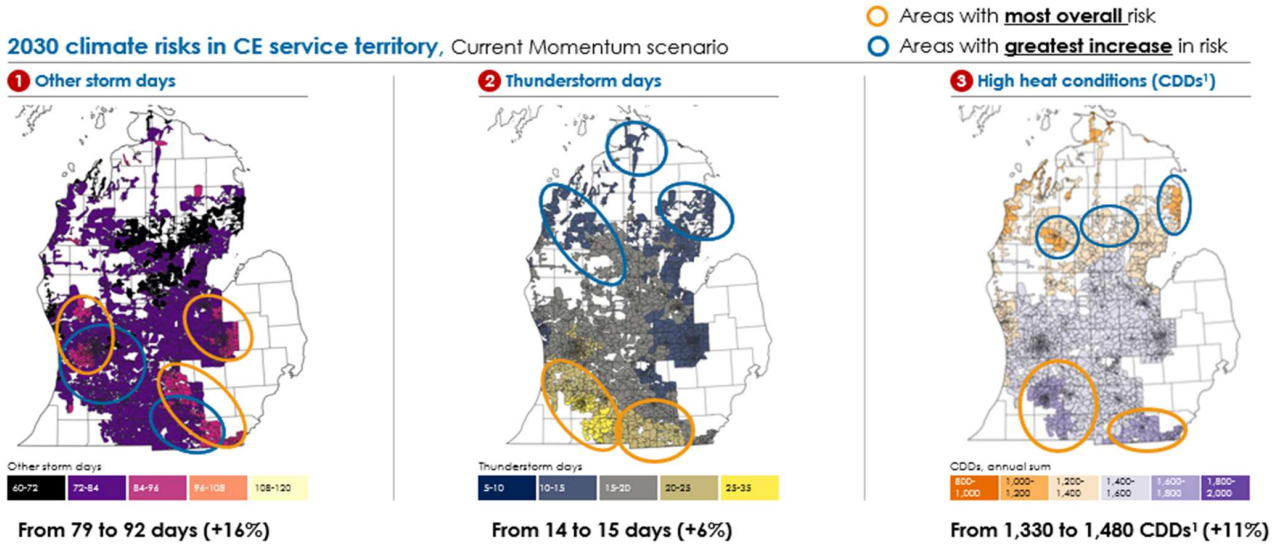


Risks are forecasted to materialize predominantly in northwestern and southern parts of the Company's service territory—by 2030, these areas see strong increases in thunderstorms (+30% / 3 days), other storms (+25% / 20 days) and high-heat conditions (+30% / 300 CDDs).

Climate risks and load impacts will significantly shape the grid environment—several areas in the Company's service territory will see their largest relative increase in climate risk as soon as in the next 7 years (e.g., 50% of increase / 20 days in storm days in Kalamazoo area may materialize by 2030), with another 50% increase realized by 2050.

Figure 17

2030 CLIMATE RISKS IN CONSUMER ENERGY SERVICE TERRITORY



Key changes, on average (maximum changes are greater) include:

Climate event	Today	Increase by 2030	Increase by 2050
Thunderstorms	17 days	~1 day (+4%)	~3 days (+17%)
Other storms	79 days	~13 days (+17%)	~21 days (+27%)
Cooling Degree Days	~1,330 CDDs	~147 CDDs (+11%)	~368 CDDs (+28%)
Days above 86°F	38 days	~12 days (+31%)	~26 days (+70%)

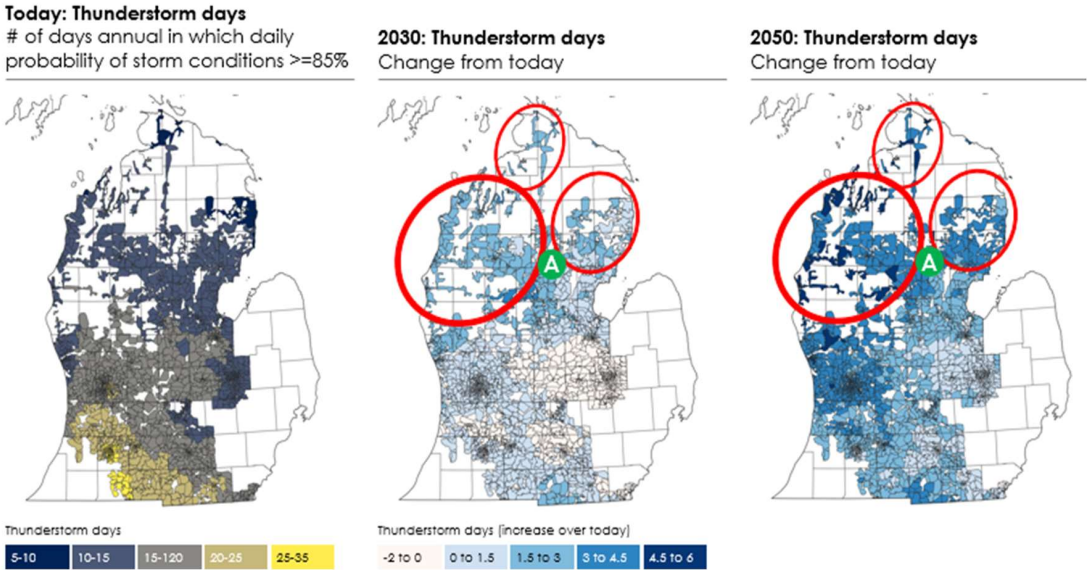
Figure 18 below depicts shifts in thunderstorm risk and the evolution from today's annual number of days with a daily probability of storm conditions greater than 85%.

Thunderstorms, defined as *events with maximum wind speeds greater than 30 mph and temperatures greater than 70°F,* are more prevalent today in southern and lower central Michigan. These thunderstorms are most associated with the high wind speeds that can disrupt the grid.

Central, northern, and eastern Michigan may experience a 30-60% increase in thunderstorm risk by 2050 (indicated by the letter A in the chart below). By 2050, 660 circuits may see a >20% increase in likely thunderstorm days.

Figure 18

2030 AND 2050 THUNDERSTORMS INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Other storm annual frequency has been studied using the number of days annually, in which daily probability of storm conditions are greater than 50%. Storms and connected occurrence of wind, have some of the highest damage potential for the Company's grid.

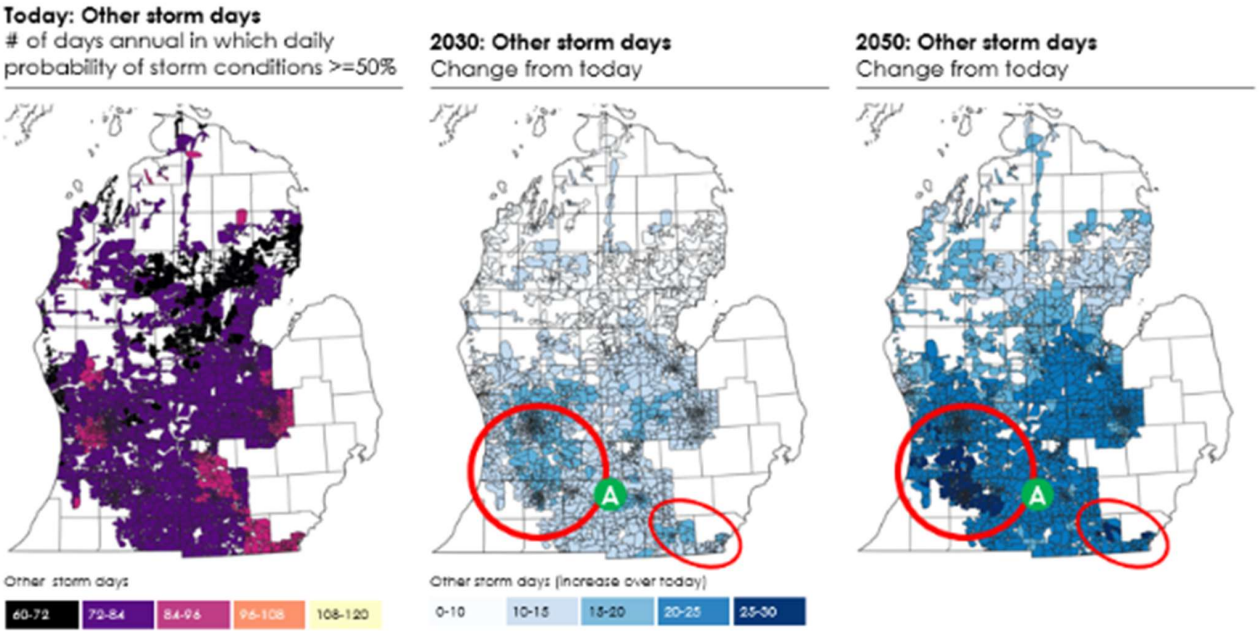
Almost all circuits (97%) are likely to experience at least a 20% increase in storm days by 2050 under a CM scenario, and nearly 20% of circuits are likely to see a 30% increase in storm days.

- As highlighted in red circles with a green letter A in Figure 19 below, **the Grand Rapids and Kalamazoo regions may see particularly large increases** with 25-30 additional potential storm days throughout the year by 2050.

As warming continues, these storms are increasingly likely to be accompanied by damaging freezing rain conditions like the catastrophic storm that swept through Michigan in February 2023, knocking out power to over 700,000 homes and businesses.

Figure 19

2030 AND 2050 STORM INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Multiple measures of high heat conditions indicate a likely increase.

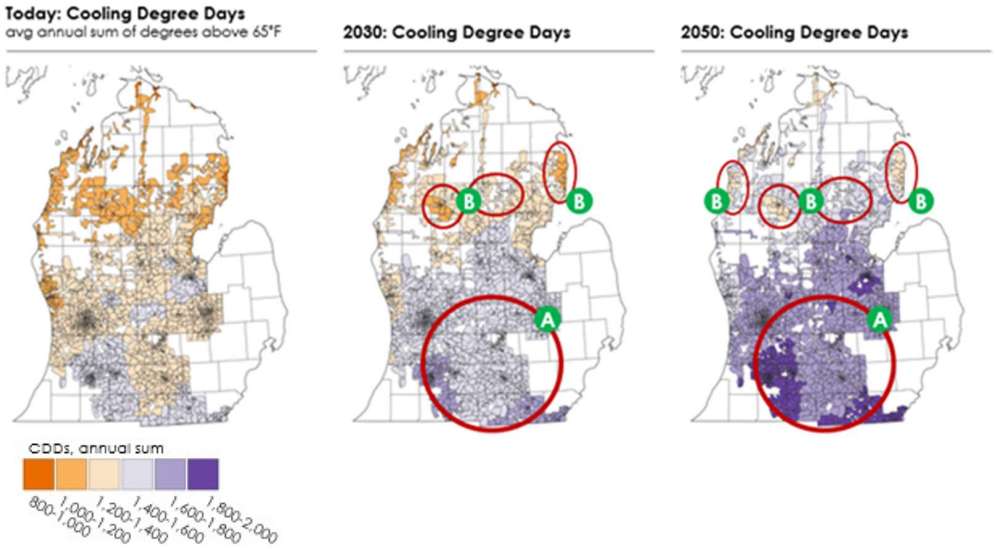
Increases in high heat conditions can result in lower line efficiency and higher customer loads, potentially bringing circuits closer to their rated capacity limits.

The largest absolute increases in cooling degree days, a benchmark used to measure broader heating, are in the southern Michigan circuits, which could see as much as 1,900 annual CDDs by 2050 (denoted by A in the Figure 20 below), an increase of 25% above today's conditions.

North central Michigan (denoted by B in the Figure 20 below) may see an even larger relative increase of as much as 33% in annual CDDs, up to 1,400 CDDs.

Figure 20

2030 AND 2050 COOLING DEGREE DAY INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



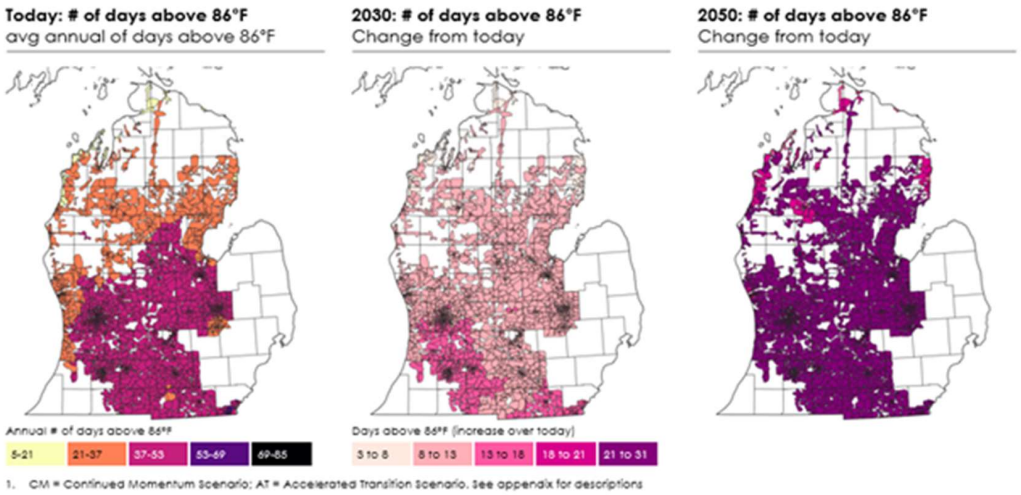
Days above 86°F, another measure of high heat conditions, can lead to reduced line efficiency of 7% and higher customer loads due to increased air conditioning usage, potentially bringing circuits closer to their rated capacity limits.

By 2050, almost all of Michigan is likely to experience more than 20 days of additional high heat. With some regions already experiencing ~50 days of high-likely air conditioning usage and line loss, this is a 40% increase from current levels.

The graph below in Figure 21 examines the average annual number of days with temperatures above 86°F in Consumers Energy's service territory.

Figure 21

2030 AND 2050 DAYS ABOVE 86 DEGREES INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Taken together, these insights can help focus grid-hardening investments today to reduce the risk of future outages.

Challenges from Customer Technology Adoption

The magnitude of modeled customer technology adoption represents a significant step-up from levels seen today.

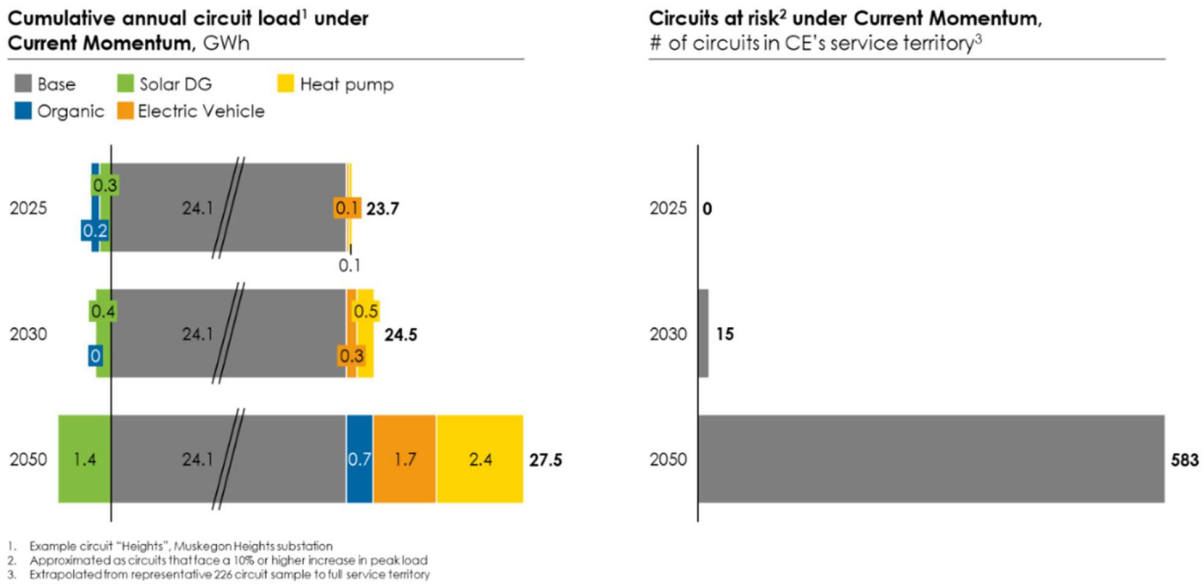
Even by 2030, and under a CM scenario, load-impacting technology adoption could greatly exceed current levels with statewide rooftop solar projected to increase to 1.3 GW, EVs projected to increase to 15% of vehicles, and heat pumps projected to increase to 15% of total households.

Load in the Company's service territory has been largely flat across the years due in part to the relatively limited adoption of electricity intensive heating and mobility technologies, coupled with the success of the Company's Energy Waste Reduction, Demand Response Programs, and summer time-of-use rates.

- Currently, EV adoption in Michigan is 1% of total vehicles and heat pump adoption is 2% of total households while solar DG encompasses 0.4 GW of installed capacity.
- Customer adoption of electrification is projected to lead to ~1-10% of circuits expected to see peak demand increase to at-risk levels by 2030 as shown in Figure 22 below.

This reinforces the Company's plan to first address the reliability impact from climate change, while continuing to develop the capacity of the grid to accommodate future low-carbon technologies.

FIGURE 22
CIRCUITS AT RISK UNDER CONTINUED MOMENTUM

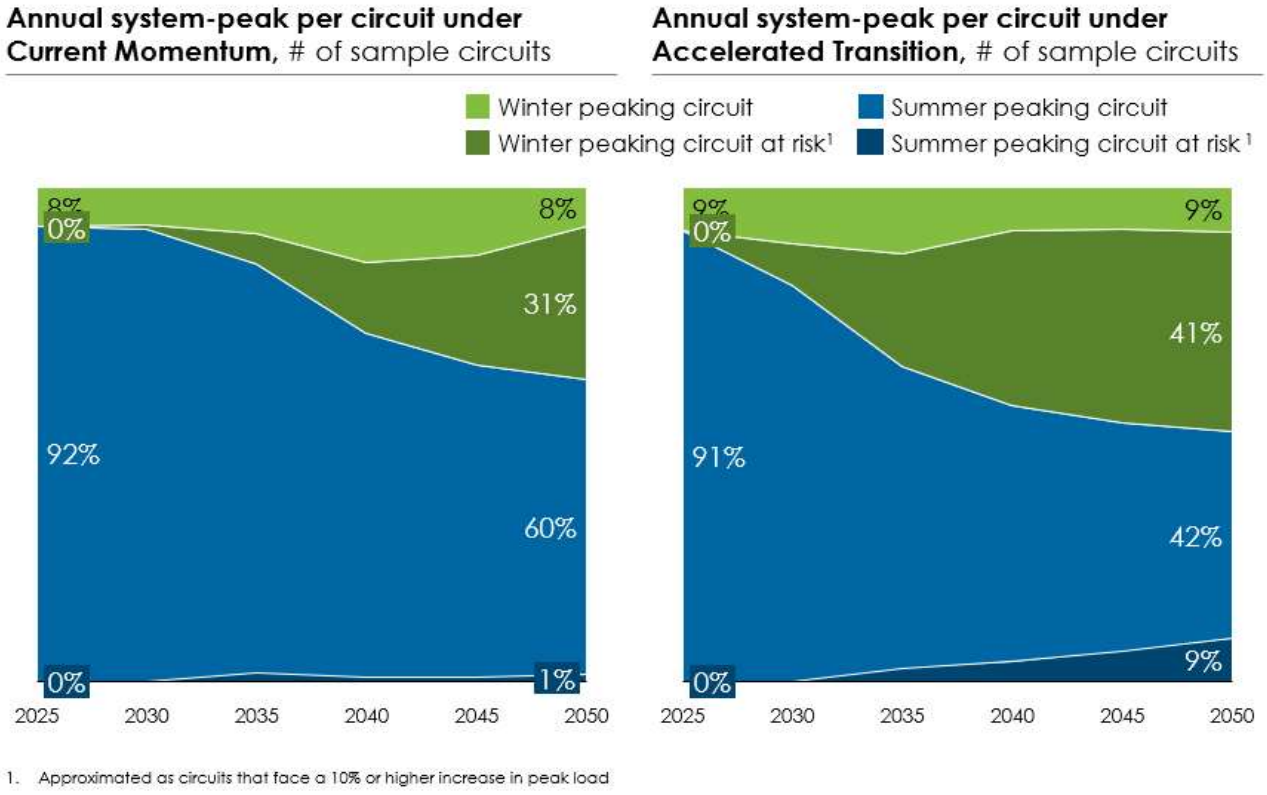


By 2050, peak load is projected to increase to at-risk levels, or greater than 10% increase in peak load, on ~25% of circuits in the CM scenario, driven by customer adoption of EVs and heat pumps.

Depending on the rate of heat pump adoption and the type of heat pumps adopted, hybrid versus fully electric, there is a potential shift from a summer-peaking system to winter peaking system with a ~50/50 summer/winter split by 2050 in the Accelerated Transition scenario as shown below in Figure 23.

FIGURE 23

ANNUAL SYSTEM-PEAK PER CIRCUIT UNDER CONTINUED MOMENTUM



1. Approximated as circuits that face a 10% or higher increase in peak load

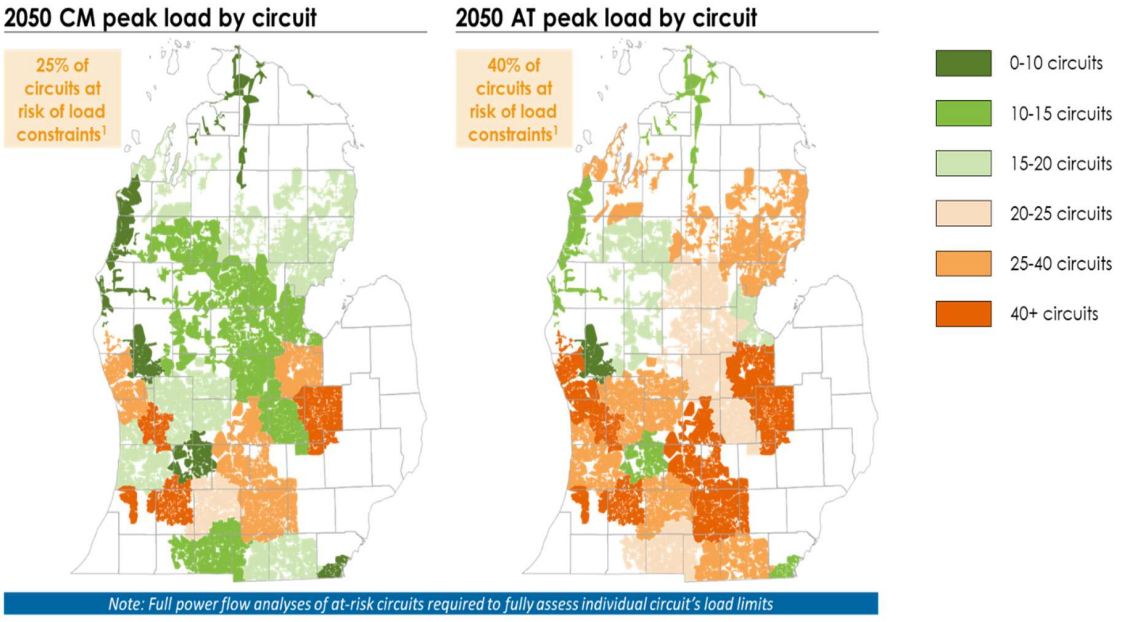
The highest levels of customer technology adoption are likely to materialize in specific circuits. Those at greatest risk of reaching load capacity limits are largely comprised of residential single-family housing customers with high household income, often in suburban areas, given a relatively higher propensity to adopt.

Circuits start reaching at-risk load threshold in 2030, and by 2050 there are 583 circuits out of 2,352 that see >10% peak load increase in a CM scenario.

In an AT scenario, 181 circuits are at-risk in 2030, with up to 40% of examined circuits at risk by 2050 (923 circuits) as shown in Figure 24 below.

FIGURE 24

PEAK LOAD BY CIRCUIT UNDER CONTINUED MOMENTUM AND ACCELERATED TRANSITION



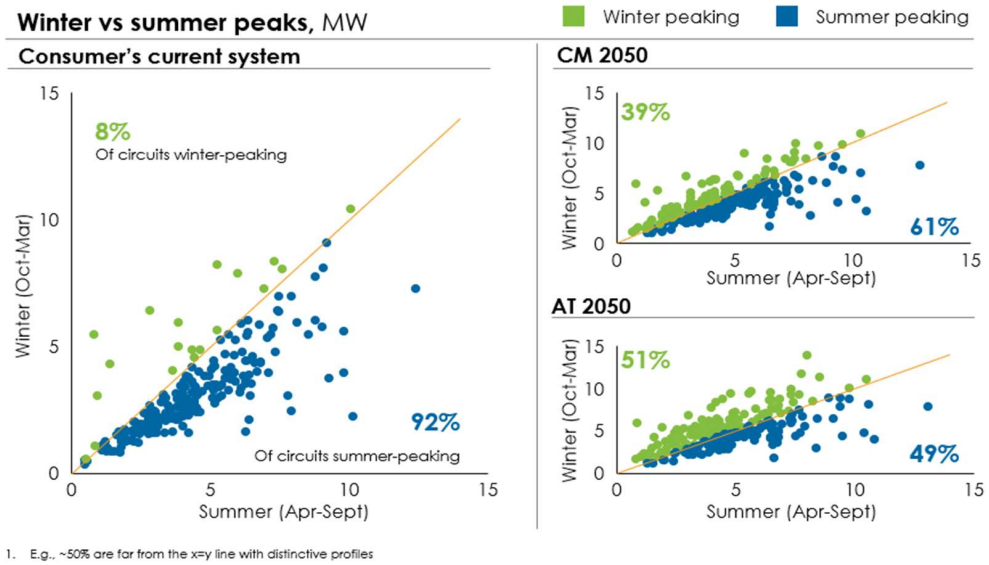
Regarding peak seasonality, summer peak increases remain relatively small—with solar DG offsetting EV load and no heat pump driven load increases.

For now, the Company primarily manages a summer-peaking system. However, the modeling for this scenario suggests this would shift in the future to winter peaking.

As Figure 25 below indicates, summer peaking could shift to winter peaking for 51% of circuits by 2050 in the AT scenario, and for 39% by 2050 in the CM scenario.

FIGURE 25

CIRCUIT PEAK LOADS BY 2050



This shift, driven by projected adoption of heat pumps and their wintertime use, results in a growing number of new winter-peaking circuits, with a substantial fraction reaching the at-risk threshold.

As adoption of electrification technologies continues, the expected circuit-level risk will be heavily impacted by both the timing and character of adoption.

Assumptions around the scale of penetration and time of use for when EVs and heat pumps use the grid have a significant effect on the volume and timeline of forecasted load constraints.

Non-Load Challenges from Customer Technology Adoption

Besides the direct load impacts of customer technology adoption of EVs, solar distributed generation and heat pumps, there is indirect impact on the Company's grid that stems from second-order effects of the uptake of these technologies. They include:

- Bi-directional power flows, especially in circuits that show a propensity to higher-than average adoption of solar DG.
- Power quality issues, stemming from increased decentralized load and generation, could unbalance power factors and degrade voltage quality.
- Interconnections with third parties to facilitate control of distributed customer technology, and to influence load and consumption profiles for the benefit of the grid.

As part of the work going forward, CE must consider such indirect challenges and plan to take action to mitigate them, while simultaneously allowing and supporting the uptake of new load technologies in the service territory.

Such action can often be taken in tandem with actions that help increase resiliency to climate risks or to load increases (e.g., encouraging uptake storage on the LVD system can help mitigate peak load concerns, while at the same time reducing the occurrence of bidirectional power flows).

Federal Energy Regulatory Commission (FERC) Order 2222 mandates that utilities must facilitate the participation of Distributed Energy Resources (DERs) such as rooftop solar in the wholesale electricity market by allowing them to be aggregated and participate alongside traditional, larger scale power sources. Under this FERC Order, utilities must work with DER aggregators to enable them to bid into the wholesale market as a single unit.

The Midwest Independent System Operator (MISO) has proposed a two-phase implementation plan, which FERC has approved. This phased approach creates a DER market in MISO, gradually integrating DERs by 2026 with full implementation of DER Aggregators by 2030.

The Company plans to begin facilitating the participation of DERs beyond demand response (DR) in accordance with MISO's timeline. The Company currently allows for the aggregation and participation of DR, as allowed for by FERC Order 888. Given the lessons already learned from overseeing third-party participation in the wholesale market for DR, the Company expects to need a robust solution for managing, overseeing, and optimizing even more DERs.

A centralized DER Management System ("DERMS") will be critical to supporting system-wide optimization of DERs, especially as the volume of resources increases and the complexity of the relationship with the resources increases with the implementation of FERC 2222.

The Company defines DERMS as *an enterprise scale software platform that is located at the utility's operational center*.

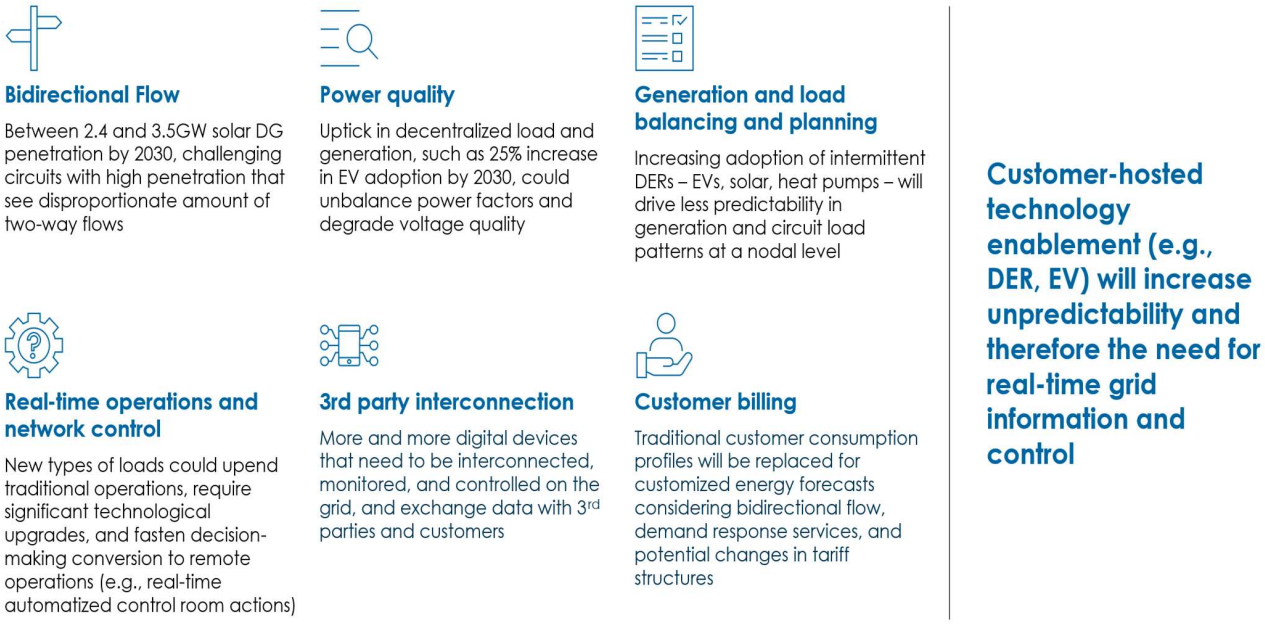
- A DERMS monitors, controls, and optimizes DERs in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system.
- This structure allows DER performance to be optimized for reliability and efficiency while simultaneously accounting for local, regional, and system-wide constraints and requirements.

Optimization at a system-wide level will be driven by bulk power constraints and requirements (e.g., frequency, capacity requirements, SAIDI, etc.).

A DERMS provides the functionality required to manage these wide-ranging factors to realize system-wide optimization. This includes coordination with other enterprise systems such as an Advanced Distribution Management System ("ADMS") detailed later in this report, and the Demand Response Management System ("DRMS").

FIGURE 26

NON-LOAD CHALLENGES FROM CUSTOMER TECHNOLOGY ADOPTION



Defining The Reliability Roadmap

In the face of the challenges outlined above, the Company developed the *Reliability Roadmap* to ramp up its investment in developing a modern grid capable of mitigating the immediate threats from extreme weather.

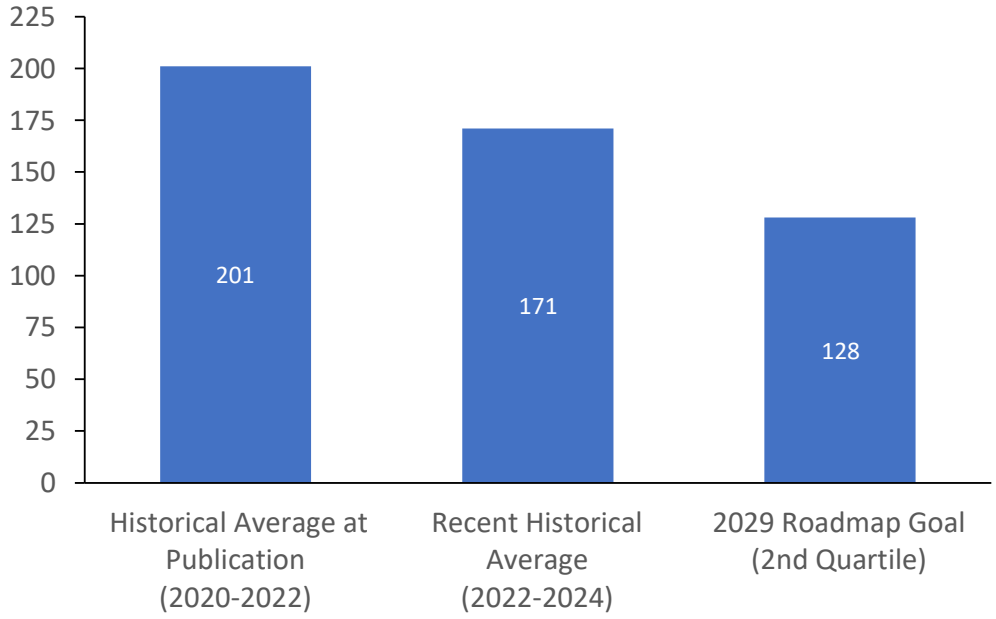
- The *Reliability Roadmap* represents an increase in the scale of infrastructure investment, spending on Forestry Line Clearing, and increased equipment inspection relative to levels set in rate cases prior to Case No. U-21585.
- It also adds additional resiliency investment, such as overhead to underground conversions, and the fractionalization of circuits and substations.

Investment at this scale will also set the Company on a path to build a grid that will ultimately deliver on the following three objectives mentioned earlier in this document:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities.**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

Additionally, investment at the scale outlined in the *Reliability Roadmap*, if approved by the Commission, will deliver significantly improved SAIDI performance by the end of the decade, as shown in Figure 27 below. These investments will provide a substantial improvement over the Company's average 2020 to 2022 performance of 201 minutes, delivering 2nd quartile performance by 2029.

FIGURE 27
SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP GOAL



The *Reliability Roadmap* differs in scope and scale from the 2021 EDIIP, which was developed prior to the Company's advanced climate and technology adoption modeling explained earlier in the Scenarios and Future Impacts to the Distribution System section of this report.

The Company anticipates the pace of reliability investment will level off after investments made to address rapidly changing climate and customer technology adoptions have been implemented.

Looking beyond 2030, the mix of investments will likely shift to ensure the system has capacity to service load from increased extreme heat days, and electrification of transit and home appliances.

The Company's SAIDI goal is achieved through numerous investments and work activities that all contribute to the overall reliability goal. These approaches can be considered in four categories: *Hardening*, *Inspections*, *Forestry Line Clearing*, and *Digital Automation*.

Hardening consists of capital investments to repair and replace HVD and LVD assets such as lines and substations.

- These investments address infrastructure on the system at risk from severe weather and allow for proactive resiliency plans, such as undergrounding or fractionalization.
- Further details on the investment categories including the 5-year investment plan and approaches to reliable operations are included in the *Asset Management* sections of this report under LVD Lines, HVD Lines, and Substations.

Inspections include ground and aerial inspections on both the LVD and HVD systems, and work related to addressing any identified failures.

- Company inspections of distribution lines and substations are used to locate and repair failed equipment, to identify specific areas to target investments based on probability of future issues, and to prioritize projects that will deliver the greatest reliability improvements for customers.
- Further detail on the investment categories including the 5-year investment plan and Company inspection cadence is included in the Overview of Asset Management section of this report under *LVD Lines*, *HVD Lines*, and *Substations*.

Forestry Line Clearing includes the work responsible for maintaining clearance between vegetation and energized Company equipment, and to eliminate the vegetation hindering accessibility to the Company's electric lines.

- This vital work is the most impactful towards improving system reliability and encompasses both HVD and LVD specific programs.
- Further detail on the Company's approach to Forestry Line Clearing including the 5-year clearing plan, best practices, and risks it responds to are discussed in the Forestry Line Clearing Program section of this document.

Digital Automation includes technology-driven solutions to increase efficiency of the Company's distribution planning work, service restoration, and line clearing operations.

- An example of this work is the Company's use of drones and Imagery Analytics to re-imagine the Company's inspection processes by providing a 360-degree view of its distribution assets in the field. This application shows **the potential to enhance employee and customer safety, reduce the cost of work, and to improve reliability and resiliency** through more targeted work.
- These investments are a key component of the Company's glidepath to achieving breakthrough SAIDI and reliability performance.
- Further detail on the Company's digital and automation can be found in the section of this plan under Grid Automation and Next Digital Investments.

FIGURE 28

IMAGERY FROM DRONE INSPECTION COMPARED TO VISUAL GROUND INSPECTION



Planning Process

Annual Planning

Distribution planning is an iterative process in which planning engineers and operators identify projects and maintenance work needed to address system performance issues and meet the Company's goals and objectives for the electric distribution grid.

All work is planned in consideration of expected customer demand and emergent replacements, planned maintenance, and improvements to the grid.

As engineers and operators identify work, this informs planned infrastructure investments, inspections and maintenance of existing assets, projected customer-requested and emergent work, and supporting staff.

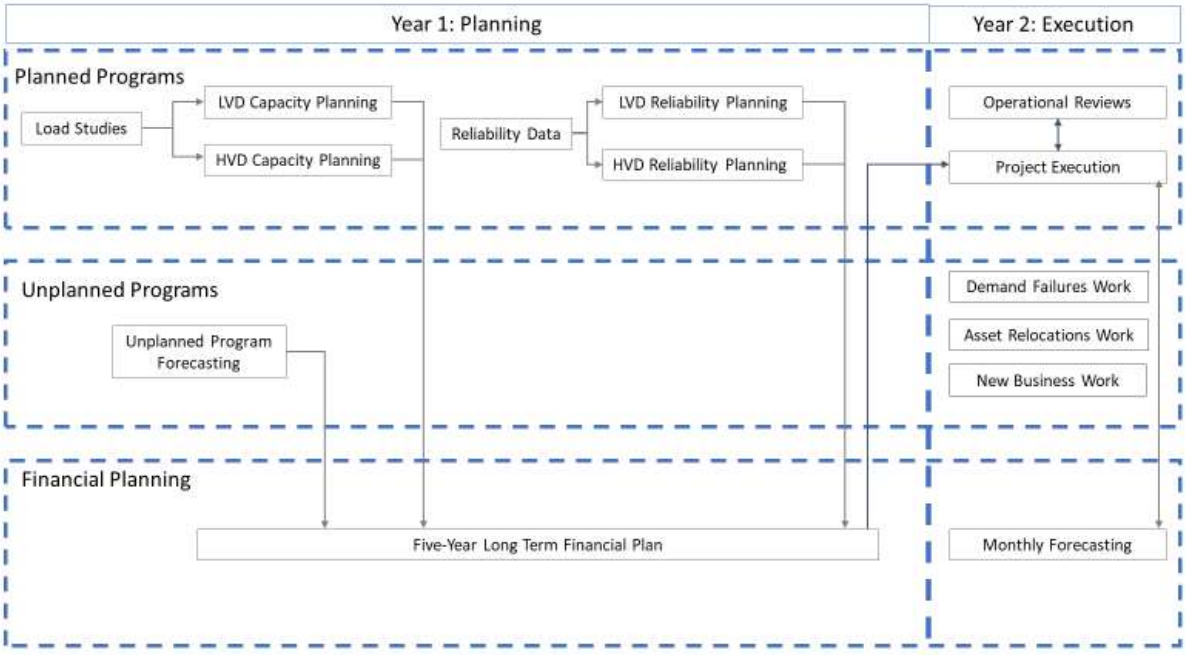
Repeating this process every year results in a rolling 5-year planning process in which one incremental year is added every cycle.

Depending on the nature of a given program, these identified investment needs are based on a combination of pre-planned or known projects, and anticipated volumes of emergent work, generally based on historical volumes of work accounting for observed trends.

Figure 29 shows how these planning activities connect with each other.

FIGURE 29

ELECTRIC DISTRIBUTION FINANCIAL AND ENGINEERING PLANNING PROCESS



To align with industry best practices, the Company has consulted the Electric Power Research Institute's ("EPRI") *Distribution Grid Resiliency: Prioritization of Options* report (EPRI, Palo Alto, CA: 2015. 3002006668) published in 2015 and made publicly available at the EPRI website.

EPRI published this report on the prioritization of options for grid resiliency incorporating research that EPRI conducted on overhead structures, vegetation management, undergrounding, grid technology, and storm response practices.

The report provides a benchmarking analysis of the costs and benefits of various options for improving reliability and resiliency, such as Undergrounding and Fractionalization, that the Company will apply to its distribution planning, as well as discussion on how to rank the reliability of circuits so that projects can be prioritized.

Engineering Planning Process Overview

The Company's electric distribution engineering planning process runs throughout the year.

The Company conducts engineering work in all programs to address specific objectives and issues on the distribution system, depending on the type of work, the affected customer profile, and the attributes of the assets in question (e.g., HVD, LVD, substations).

The Company makes capital investments under two broad classifications, known as *unplanned* and *planned*.

***Unplanned* capital investments** correspond to customer requests or emergent system needs, such as for new business connections, restoration of service after storms, or requests for asset relocations. In the Company's electric rate cases, these capital investments fall in the New Business, Demand Failures, and Asset Relocations investment programs.

These investments are not strictly 'unplanned' as the Company does anticipate having to make these investments but is usually unable to plan specific projects until an interruption or defect occurs, the Company receives a request from a customer or another project-triggering event occurs, such as a broken crossarm.

The defects identified from inspection and maintenance programs, described further in the Overview of Asset Management section, are unknown prior to identification but are prioritized for mitigation based on safety and reliability risk.

Instead, using a variety of external economic and industry indicators the Company can (to some extent) forecast related volumes of work, funding required, and detailed analyses of the state of the system in advance. For example, the Company uses data from the *Home Builders Association of Michigan* to estimate new housing starts to help forecast future spending on new service connections.

***Planned* capital investments** proactively improve reliability, address capacity constraints, and invest in new tools and technology. In the Company's electric rate cases, these capital investments fall in the Reliability, Capacity, and "Electric Other" investment programs.

For these investments, the Company prioritizes investments to maximize customer benefit in the most cost-effective manner. Specific investment prioritization varies based on the type of asset, but broadly speaking the Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize customer reliability, identifying specific investments based on the probability of future issues.

Different components of distribution planning—for example, planning for LVD lines or HVD substations—are overseen by respective program managers, who are responsible for developing plans in those areas.

Under these program managers, engineering planning leads and individual engineering planners have responsibilities for developing specific projects. Investment planning for the *planned* investments broadly follows three stages:

1. **Reviewing system needs** – Engineering planners review system needs to identify critical target areas at an LVD circuit, LVD zone, LVD or HVD substation or HVD line level, using a variety of asset-specific technical inputs and analytical tools, including real-time data and inspection results.
2. **Determining required actions and developing projects** – Once a customer or system need is identified, engineering planners determine required actions and develop concepts that compare alternatives and identify a recommended project based on the most economical and effective solution, such as to repair the damaged asset or replace it.
3. **Prioritizing and sequencing work** – Program managers and engineering planners prioritize, and sequence projects based on project timelines, customer benefits, system-wide workload balancing, and customer base balancing.

In certain investment areas, particularly for the LVD system, the Company uses an additional initial step in its process for grouping circuits and identifying projects, known as *Grid Archetypes*. Many larger individual projects are evaluated using a *Concept Approval* process. Both topics are discussed later in this Planning Process section.

In 2024, the Company also began using Copperleaf to further improve its planning process and its project optimization. Full implementation of Copperleaf will take time, but the Company expects to more fully integrate it into its planning processes throughout 2025. Copperleaf is described in more detail below.

Concept Approval Process

To ensure its electric distribution investments are reasonable and prudent, the Company considers many of its planned electric distribution investments against alternatives and develops concept approval documentation to demonstrate why the selected project is the optimal investment to make.

Through this internal concept approval process, the Company ensures the problem is clearly defined, alternatives are evaluated based on cost and solution to the problem, and there is a strong business case for the recommended project.

The general structure of a concept approval includes the following:

- Background and identification of problem
- Evaluation of alternatives
- Determination of costs and benefits of alternatives
- Selection of best alternative
- Approvals and revisions, where necessary

Based on the Company's identified goals, program managers provide direction to the Company's engineering planners regarding the types of work to be targeted.

Engineering planners gather data and perform problem solving to identify alternatives and eventual selection of a project. Once the engineering planners have identified alternatives, selected a project, and drafted a concept approval, they are reviewed by successively higher levels of management based on the projected cost for the selected project.

For small projects, no approval may be needed beyond that of the engineering planning director. In most cases, projects approved by the engineering planning lead go on to the program manager for review and approval, and may go higher for further review, depending on the projected cost of the project.

At each level of review, the reviewing party may request further revisions.

Once a concept has received all necessary approvals, it is considered an approved part of the Company's investment plan. It is released to the Company's electric design engineers for detailed design work, which consists of the following:

- During the design phase, costs may vary slightly from the original concept approval cost projections.
- If costs vary significantly based on design work, the variance may be reviewed by the program manager and engineering planner and, if necessary, resubmitted for approval with revised costs.

- If there are no significant financial variances between concept approval and the finished design, then the project proceeds to construction.

At this point, the Company's Planning and Scheduling group identifies and assigns either Company or contractor workforce resources to the project (depending on project specifics) and the project is scheduled for execution.

During construction, the program manager regularly reviews actual costs incurred against the budget. Unexpected cost variances during construction are managed through the Company's ongoing monthly budgeting process, with adjustments to the overall workplan made as necessary to manage to budget.

Asset Investment Planning Optimization

Copperleaf is an Asset Investment Planning ("AIP") decision analytics software solution, designed to support critical infrastructure investment planning for industries including electric utilities. Copperleaf combines financial and non-financial metrics to provide a comprehensive framework for evaluating, prioritizing, and optimizing investments, enabling organizations to make more strategic and data-driven decisions about their asset portfolios.

Copperleaf operates using a "Value Framework," a customizable set of models that quantify the benefits associated with various types of investments.

Copperleaf evaluates projects against specific "value measures" within these frameworks, encompassing multiple categories of benefits, such as risk mitigation, reliability improvements, cost savings, regulatory compliance, and customer satisfaction. By assigning a measurable value to each of these factors, Copperleaf enables organizations to compare projects objectively, weighing both their immediate financial returns and broader, long-term benefits.

- Copperleaf is particularly valuable because it can assess projects through both financial and risk-based valuations. Copperleaf employs risk-adjusted project prioritization, using a structured approach to identify high-risk assets and projects that, if left unaddressed, could lead to significant future costs or reliability issues.
- This risk-based approach includes metrics like Probability of Failure and Consequence of Failure, which provide a quantified understanding of the impact of each asset or project on the system's overall stability and resilience.
- Copperleaf's optimization capabilities will allow the Company to build a project portfolio that better supports its distribution objectives. By integrating projects into a unified system, the software can run different investment scenarios to determine the optimal plan that balances financial constraints with maximum system-wide benefits.

For Consumers Energy, implementing Copperleaf means distribution projects can be systematically analyzed and optimized. Systematic project optimization will enable the organization to proactively address aging infrastructure, improve system reliability, and meet regulatory requirements, all while enhancing customer satisfaction through reduced outages and optimized grid performance.

Grid Archetypes

Since 2018, the Company has developed and used an approach referred to as *Grid Archetypes* to consider additional LVD circuit characteristics beyond traditional reliability metrics of SAIDI, SAIFI, and CAIDI, when assessing grid performance.

This approach ensures no section of the grid is inadvertently left behind—that **both rural and urban customers, and residential, commercial, and industrial customers all benefit equitably** from the Company's investments, by making sure that investments are optimally made across the Company's distribution system.

In the Archetypes approach, the Company groups each of its LVD circuits into one of seven archetype categories based on various circuit characteristics. Circuit characteristics include geographic characteristics (i.e., circuit line-miles, distance to Company service centers), customer mix, circuit load and voltages, and reliability metrics. Full details on all circuit characteristics and their use can be found in Appendix A.

Figure 30 below defines each Archetype and illustrates where each of the Archetypes are located throughout the Lower Peninsula.

FIGURE 30

GRID ARCHETYPES



Once the LVD circuits are grouped, Company leadership establishes multi-year goals and broad budget guidance. This guidance provides multi-year guidance on guardrails for how much investment should be allocated to each archetype.

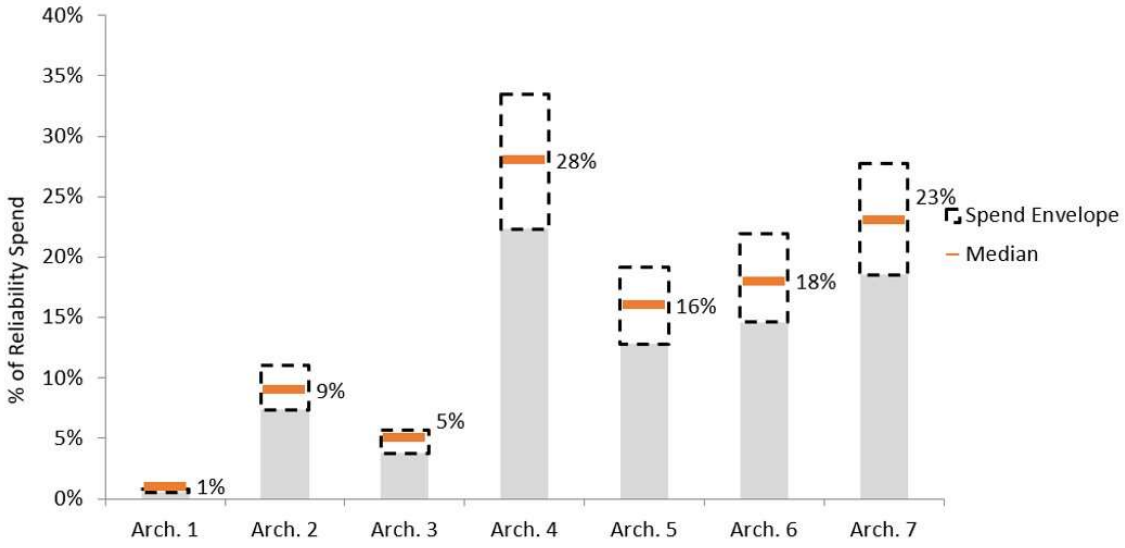
During this process, the Company takes its planned, systemwide LVD capital spending for a given year and allocates the spending to each archetype based on different archetype characteristics or archetype performance measures.

The Company then takes the median allocation of all allocations and calculates spending guardrails for each archetype based on a certain amount of allowable variance. An illustrative example of these calculations is shown in Appendix A.

The result of this process is an illustration of targeted spending ranges for each archetype, as shown in Figure 31 below.

FIGURE 31

ARCHETYPE TARGETED SPENDING RANGES – ILLUSTRATIVE EXAMPLE



	Arch. 1	Arch. 2	Arch. 3	Arch. 4	Arch. 5	Arch. 6	Arch. 7
% of Line Miles	1%	6%	4%	18%	25%	17%	29%
% of Customers	1%	8%	9%	41%	14%	9%	18%

If the Company's planned spending in each archetype falls outside the "spend envelope" guardrails, then spending can either be reallocated to better ensure optimal prioritization of investment across the LVD system or the Company can develop a justification for why spending outside of the guardrails is necessary.

Equity and Environmental Justice in the Planning Process

Analyzing Equity of Distribution Performance

Since the Company filed its second five-year EDIIP in June 2021, the MPSC and other parties have indicated increasing levels of interest in EJ, energy equity, and other similar topics.

For purposes of distribution planning, these issues primarily concern how different communities experience reliability and resiliency, as well as future implications for grid access when it comes to customer adoption of EVs and other electric technologies and customer adoption of distributed energy resources.

Reliability and resiliency concerns are pronounced because people living in disadvantaged communities may have more difficulty replacing spoiled food and medicine following power interruptions, and may have fewer resources to secure back-up power or find alternative accommodations during extended power outages.

In its September 8, 2022, Order in Case No. U-20147 ("September 8 Order"), the Commission provided expectations around EJ and energy equity data to be shared in this EDIIP, directing utilities to provide information on the distribution system, particularly maps providing system information overlaid with socioeconomic context.

Additionally, in the settlement agreement for the Company's Electric Rate Case, approved by the Commission in Case No. U-21224 ("Settlement Agreement"), the Company agreed to further provisions around data that would be shared, as well as ways the Company would work to incorporate EJ considerations into distribution planning.

These concerns were substantially addressed in the 2023 version of this Reliability Roadmap, as well as in the Company's 2023 and 2024 electric rate cases (Case Nos. U-21389 and U-21585). Those analyses built on one another, and indicated that:

- On a systemwide basis, the Company's EJ communities have comparatively good reliability; but
- There are particular EJ communities that do face reliability challenges

The Michigan Department of Environment, Great Lakes, and Energy ("EGLE") has developed the MiEJScreen tool to assess the vulnerability of census tracts based on various inputs, creating a score from 0-100, with 100 indicating the most vulnerable communities. The Company has defined any census tract with a MiEJScreen score of greater than 80 as an "EJ census tract."

Electrical geography does not always match political geography, and the Company uses the term "EJ circuit" to refer to any LVD circuit that serves an EJ census tract in whole or in part. Because of this, some EJ circuits include individual customers who do not reside in EJ census tracts. When the context is more general, the Company sometimes uses the term "EJ communities" to describe the general concept of vulnerable customers in a certain defined area.

The Company has 249 total circuits overlapping in whole or in part with EJ census tracts, as defined in the Settlement Agreement; of these, 24 are customer-owned or single-customer-dedicated circuits, leaving 225 general distribution circuits serving EJ customers according to this definition.

The Company's data has consistently shown that EJ census tracts, when considered together, consistently have better reliability performance than other census tracts in the Company's service territory.

In the summer of 2024, the Company performed two different analyses to probe further into reliability concerns for EJ communities. These two analyses both address the same general concern, but they are independent of each other and there is no meaningful way to cross-reference them against each other; each one stands alone in its analysis.

First, the Company analyzed how many individual EJ circuits have poor reliability that is being obscured by good reliability on other EJ circuits that averages out in a systemwide analysis. To do this, the Company compiled all 190 EJ circuits on its system and reviewed their individual SAIDI, both including and excluding MEDs, over the past five years.

The Company then compared each EJ circuit's SAIDI scores against the Institute of Electrical and Electronics Engineers ("IEEE") quartiles. The Company found that, over the period from 2019 through 2023, 118 of the 190 EJ circuits had average SAIDI excluding MEDs that were in the first or second IEEE quartile, indicating better than average SAIDI. A full 80 EJ circuits had first-quartile SAIDI excluding MEDs. These first and second-quartile circuits serve about 97,000 customers.

On the other hand, 72 EJ circuits had average SAIDI excluding MEDs in the third or fourth IEEE quartile; these circuits serve approximately 78,000 customers.

The Company found somewhat similar results for SAIDI including MEDs, but with proportionally fewer circuits and customers in the first quartile and more circuits and customers in the fourth quartile.

FIGURE 32

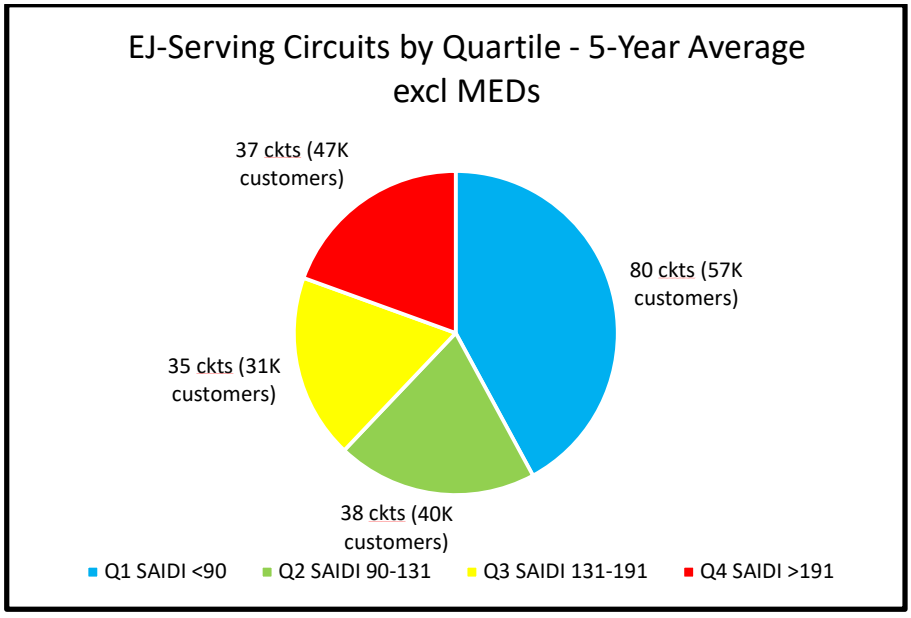
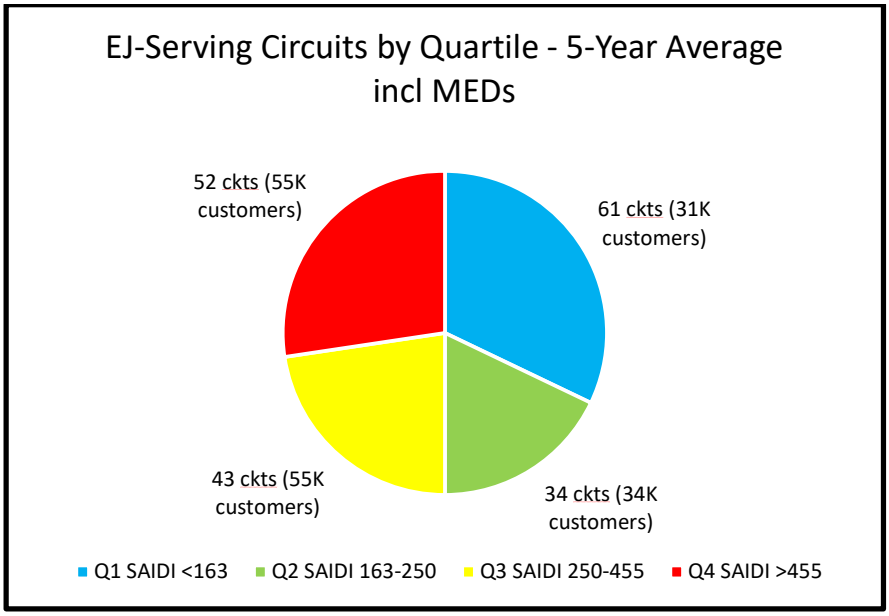


FIGURE 33



This analysis clearly indicates that some EJ communities face challenging reliability issues, which are only magnified by the vulnerabilities that these communities face when dealing with interruptions.

Second, the Company conducted another analysis over the summer of 2024 to more closely study how EJ census tracts perform relative to similar non-EJ urban census tracts. The Company has 56 EJ census tracts in its service territory, and all of them are defined as urban by the U.S. Census Bureau.

For this analysis, the Company compared the 56 EJ census tracts to similarly situated urban non-EJ census tracts. For *each* of the 56 EJ census tracts, the Company identified the five non-EJ urban census tracts that were most like the respective EJ census tract in terms of population size and housing density. Therefore, each of the 56 EJ census tracts was matched up with five corresponding non-EJ urban census tracts, meaning the Company could make 280 total comparisons of EJ census tract vs. non-EJ urban census tract performance (56 x 5).

The Company then made these 280 census tract performance comparisons for 12 different reliability metrics:

- SAIDI including MEDs
- SAIDI excluding MEDs
- SAIFI including MEDs
- SAIDI excluding MEDs
- Customer Average Interruption Duration Index (“CAIDI”) including MEDs
- CAIDI excluding MEDs
- Customers Experiencing Multiple Interruptions (“CEMI”)-4
- Customers Experiencing Lengthy Interruption Duration (“CELID”)-5
- All-weather 36-hour restoration percentage
- Catastrophic 48-hour restoration percentage
- Normal condition 8-hour restoration percentage
- Gray-sky 24-hour restoration percentage

The Company performed the 280 census tract performance comparisons for these 12 metrics for each of the five years from 2019 through 2023, yielding a total of 16,800 individual data points (280 x 12 x 5).

For each individual data point of comparison, the Company determined whether the EJ census tract or the non-EJ urban census tract with which it was being compared performed worse. To illustrate this, consider an EJ census tract *Y*.

- Census tract *Y* would have been paired with five non-EJ urban census tracts: *A, B, C, D,* and *E*. For SAIDI including MEDs in 2023, the Company would compare *Y*’s results with those of *A, B, C, D,* and *E* separately.
- The Company would count each time *Y* had the higher SAIDI, and each time one of the other census tracts had a higher SAIDI. For *Y*, this would then be done for each metric and each year.

The Company did this for all 56 EJ circuits, and totaled up how often the EJ census tract performed worse, and how often the non-EJ census tract performed worse.

FIGURE 34

Reliability Metric		Which Performs Worse on Average?	How Often is EJ Worse?
SAIDI	excl MEDs	EJ	51.29%
	incl MEDs	EJ	54.75%
SAIFI	excl MEDs	EJ	57.84%
	incl MEDs	EJ	58.27%
CAIDI	excl MEDs	Non-EJ	42.88%
	incl MEDs	Non-EJ	45.47%
CEMI-4		EJ	64.82%
CELID-5		EJ	50.22%
Restoration Time	All-Weather 36-hr	EJ	69.92%
	Catastrophic 48-hr	Non-EJ	41.58%
	Normal 8-hr	EJ	57.27%
	Gray-sky 24-hr	EJ	59.06%

These results indicate that if you take the Company's EJ census tracts and compare them, on a granular basis, with the most comparable non-EJ urban census tracts, the EJ census tracts often perform worse on key reliability metrics. The percentages indicate that the EJ census tracts perform worse on a moderately more often basis.

Vulnerable Communities Resiliency Plan

The Company does not believe it is "good enough" to point to systemwide averages, as good as they may be, and let it go at that, leaving some vulnerable customers behind.

To address the issue of customers in EJ communities facing poor reliability, the Company has developed its *Vulnerable Communities Resiliency Plan*. The purpose of this Plan is to make targeted strategic investments on EJ circuits so that every EJ circuit has SAIDI including MEDs that is in the second IEEE quartile or better.

In other words, the *Vulnerable Communities Resiliency Plan* will eliminate EJ circuits experiencing worse than the industry average, and it will do so including MEDs to account for the actual experiences of those customers.

The total proposed investments are as follows, to take place over 10 years:

- Fractionalization: $200 million of total investment
  - Six new substations – one for each EJ circuit with over 3,000 customers
  - 133 new circuit exits – one for each EJ circuit with over 1,000 customers
- LVD line rebuilds: $350 million of total investment
  - Rebuild 665 miles of primary LVD circuit to create a high-reliability mainline three-phase (i.e., aerial spacer cable or underground, based on local conditions)
- Other work: $50 million of total investment
  - 400 new reclosers to ensure no protective zones exceed 2 miles in length
  - 335 new switches (i.e. one every mile)
  - Approximately 3,000 additional fuses

While the new substations were already included in the Reliability Roadmap in 2023, the remainder of the investments are incremental. It is crucial to emphasize that t**he Company is not proposing to take reliability investments that are already in the Reliability Roadmap and redirect those to focus on the *Vulnerable Communities Resiliency Plan***, which would disadvantage customers in other parts of the Company's service territory.

The Company will maintain its planned reliability investments and then perform these targeted EJ investments in addition to those.

Note that in the Settlement Agreement as part of Case No. U-21224, the Company committed to "propose a plan to incorporate environmental justice and equity into the Grid…Archetypes analysis which the Company uses to prioritize its distribution investments in rate cases." The Company did so in the summer of 2023, and added a new reliability 'flag' to the Grid Archetypes process.

By adding EJ status to the list of reliability flags, an EJ circuit that previously only triggered one reliability flag (and therefore was not prioritized) would instead be prioritized.

However, the Company believes the new *Vulnerable Communities Resiliency Plan* effectively supersedes this EJ flag methodology. The purpose of the EJ flag was to modestly weight investment decisions in favor of EJ communities. The *Vulnerable Communities Resiliency Plan* will instead **directly steer critical investments to those communities** in a dedicated program.

Other Efforts in EJ Communities

In addition to the *Vulnerable Communities Resiliency Plan*, the Company is also proposing targeted replacement of open-wire secondary, which heavily impacts EJ communities in the Company's service territory. Furthermore, the Company is proposing to convert non-standard voltages to standard voltages.

These conversions of non-standard voltages will:

a. Eliminate ungrounded conductors, which can pose safety hazards.

b. More easily facilitate load transfers to reduce outage times.

c. Improve the capacity of the circuit to accommodate increased load in some cases.

The Company's plans for open-wire secondary and non-standard voltages are discussed in more detail later in the LVD Safety-Focused Issues and Investments section of this report.

Further Analysis

The Commission's final Order in Case No. U-21389 directed the Company to develop a regression analysis to statistically study the interaction between EJ issues and distribution reliability, in addition to the analyses discussed above.

The Company has developed that analysis, and it is being filed as an exhibit in Case No. U-21870, concurrent with this update to the Reliability Roadmap. Based on the Commission's final Order in Case No. U-21585, the Company anticipates it will update this regression analysis periodically going forward as well.

As the Company executes these plans for EJ communities, it recognizes the need to hear direct input from representatives of impacted customers in those communities, and the Company will explore avenues to get that input through appropriate channels.

- The Company has been an active collaborator in the MPSC Staff's Energy Affordability and Accessibility Collaborative; this ongoing workgroup provides a cross-functional way for utilities and other organizations to discuss challenges in energy equity, and the MPSC's process includes representation for low-income customers and other opportunities for those customers to be heard.
- The Company's Community Affairs team regularly reaches out through a variety of communication channels to local governments, community organizations, and individual customers regarding plans for major projects, including those designed to improve reliability in an area.
- The Company is willing to explore an annual meeting during which affected customers and their representatives can get information and provide input on the Company's efforts in EJ communities.

The 2023 version of the Reliability Roadmap included maps overlaying reliability data for EJ circuits and EJ census tracts. The Commission's Order in Case No. U-21389 directed the Company to work with Staff to develop a means for interested parties to access Geographic Information System ("GIS") data from the Company, and the Company undertook this effort during late 2024 and early 2025.

As one outcome of this, the Company has now posted interactive GIS maps to its public website that overlay EJ circuits and EJ census tracts with the ability to view SAIDI and SAIFI data both with and without MEDs. This is available at:
https://experience.arcgis.com/experience/1d84e089ff5e4a2382df340d15689488

Hosting Capacity in EJ Communities

The Settlement Agreement in Case No. U-21224 also included a commitment by the Company to include data on hosting capacity in EJ communities in future filings. To date, the Company's hosting capacity analysis has largely been limited to an initial "go/no-go" analysis that was discussed in the 2021 EDIIP and published in detail on the Company's website in the fall of 2021.

Information based on that analysis relating to EJ communities was provided in the Company's 2023 electric rate case in Case No. U-21389. As discussed later in this updated version of the Reliability Roadmap, the Company is working in 2025 on further developing its hosting capacity analysis capabilities, which will deliver the ability to better study hosting capacity for EJ communities as well.

Overview of Asset Management

The *Reliability Roadmap* reflects the Company's strategy to meet the safety, equity, reliability, and resiliency needs of customers through the grid both now and into the future. This plan focuses on assets to modernize the Company's electric distribution system to safely provide power with fewer, shorter, and less frequent power outages for customers.

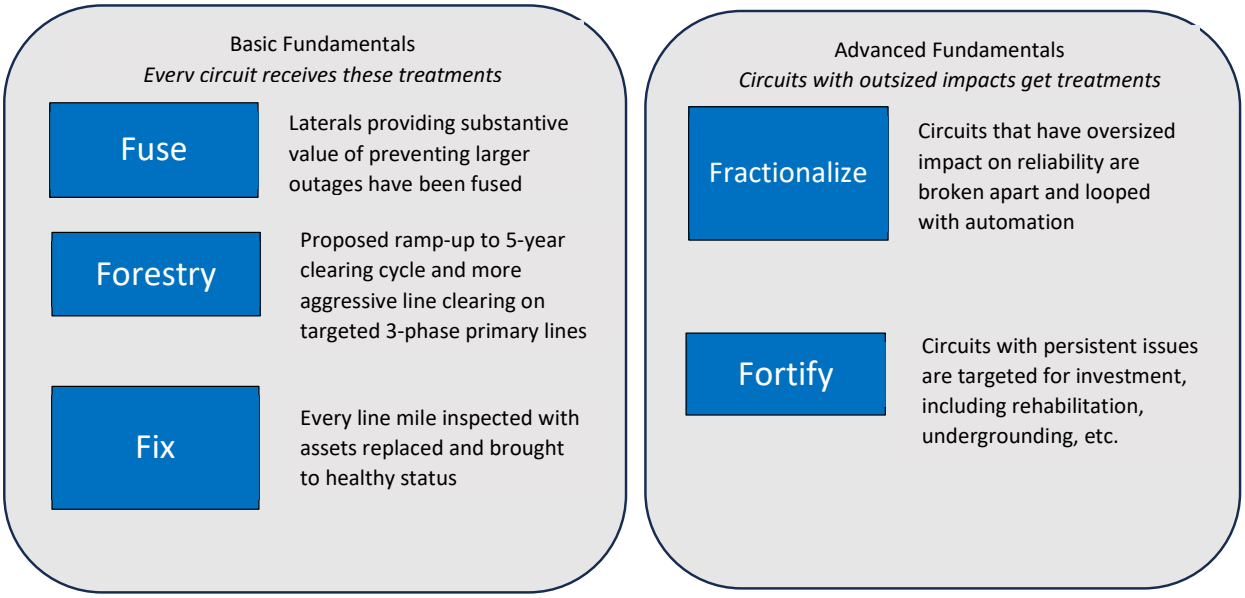
The Company's distribution system consists of several classes of assets. LVD lines, HVD lines, the Metro System, and substations were introduced earlier in the Distribution System Overview section of this report. In addition to these major classes, the distribution system also includes the protective system; distribution meters; distribution transformers; and streetlights.

The Company developed a strategic approach for each asset class to identify risks that affect reliability performance; developed countermeasures to mitigate those risks; created a workplan that implements those countermeasures in a prioritized manner; and defined an investment plan needed to support that work.

Each investment plan includes the planned Capital expenses to construct the distribution assets, and the Operations and Maintenance ("O&M") expenses for assets' annual inspections and upkeep, where applicable.

Each workplan is characterized by the Five Fundamentals Approach (Five Fs) shown in Figure 35 below, which succinctly covers the various approaches the Company uses to ensure reliable operations. By following this approach, the Company's investments are designed to improve system performance while ensuring circuits perform as expected.

FIGURE 35
FIVE FUNDAMENTALS APPROACH



The next several sections of this document will discuss the Company's specific asset management approaches for each asset class: LVD lines, LVD transformers and meters, Metro, HVD lines, substations, and system protection, plus additional topics like streetlights. In each case, the plan will outline the risks each subclass faces, a workplan tailored to address the most urgent risks, and the 5-year investment needs to execute this plan.

LVD Asset Management

LVD Lines Overview

This section focuses specifically on LVD Lines, which consist of several sub-classes of assets, each with a specialized asset management approach.

The entire distribution system contains approximately 107,000 miles of LVD lines, including 61,000 of Primary and 46,000 miles of Secondary as shown below in Figure 36.

FIGURE 36
LVD PRIMARY LINES MILES BY TYPE

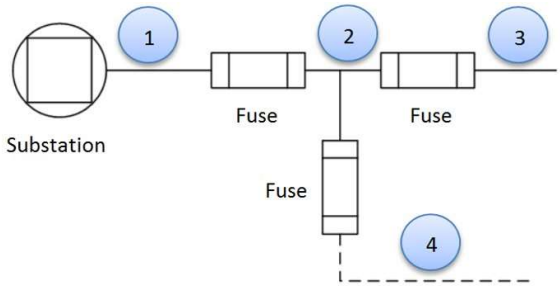
	Overhead	Underground	Total
LVD Primary Line Miles	51,736	9,885	61,621
LVD Secondary Line Miles	31,209	18,474	49,683
Total	82,945	28,359	111,304

In 2024, the LVD system comprised approximately 2,400 circuits, although some of these circuits are dedicated to a single customer or are part of the Metro system.

LVD circuits are subdivided into protective zones, as shown in Figure 37 below. As November 2024, the LVD system was apportioned into approximately 156,000 protective zones, with the number continuing to grow as the Company makes investments into the system to increase sectionalization and decrease the size of outages impacting its customers.

- Beginning in 2022, the Company set out to fuse overhead laterals to mitigate the size of outages by reducing the average number of customers out for an outage incident or event, lessening the impact of a fault to a smaller number.
- By the time this program is complete in 2025, the Company will have added approximately 28,000 fuses, reducing 41,000 customer outages annually and saving an estimated 9 minutes of SAIDI.

FIGURE 37
ILLUSTRATION OF CIRCUIT SUBDIVIDED INTO ZONES



Additionally, the LVD system includes approximately 1.5 million poles—1.1 million on the primary system, and 400,000 on the secondary system.

Based on the Company's historical data, the overall average lifecycle of an LVD primary circuit is expected to be 57 years. The average age of an LVD pole is 40 years.

The **largest reliability risks to the LVD lines system are those that lead to outages and interruptions to customers.** The two largest contributors to frequency of outages (measured by SAIFI) on the overhead LVD system are **trees and asset failures**.

Besides frequency of outages, **duration of outages (measured by CAIDI) contributes to LVD lines risk**. Much of this outage duration risk is addressed through the Company's Service Restoration efforts, but there are also outage duration implications of system configuration.

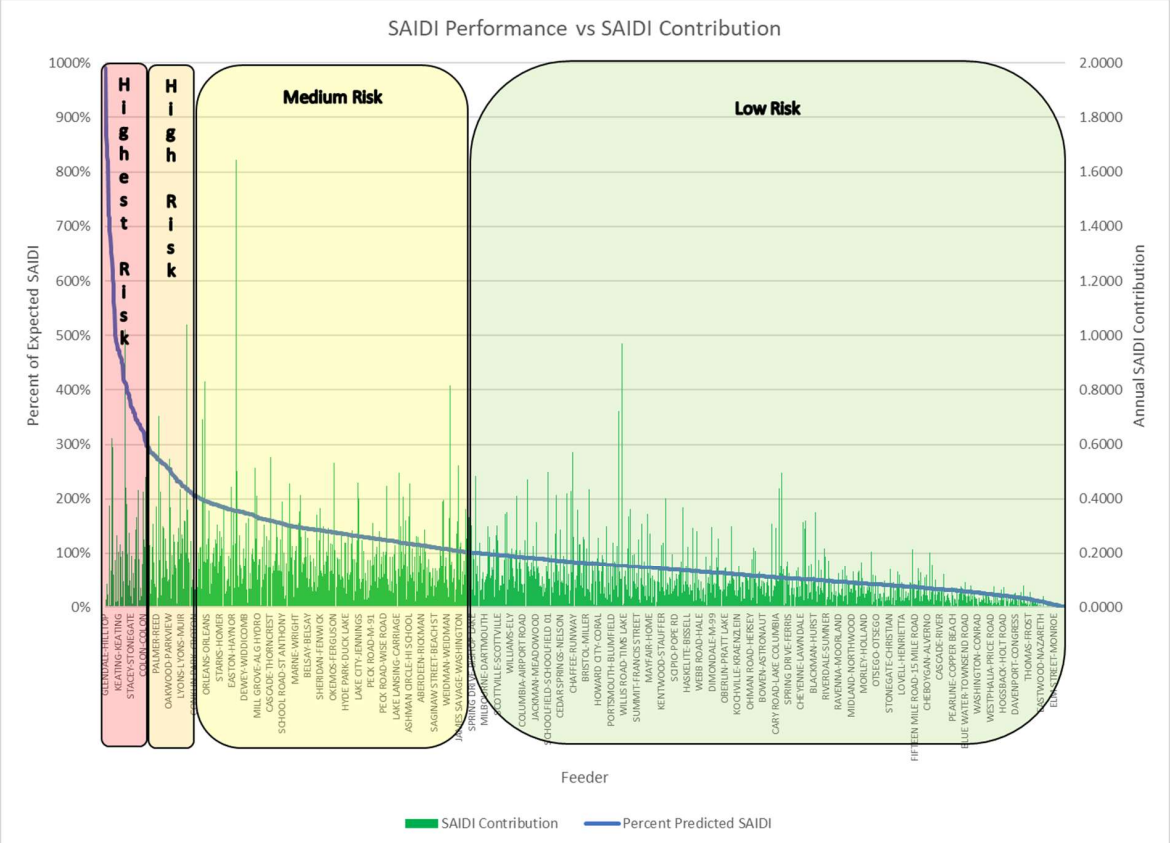
- The chart below in Figure 38 shows all LVD circuits within the Company's service territory on the horizontal axis with two measures of reliability performance on the vertical axis (the right side of the vertical axis shows actual SAIDI contribution, while the left side shows the percentage of expected SAIDI).
- The **100%** line on the vertical axis represents a circuit performing as it is engineered, while any green lines extending above this line represent circuits performing worse than expected.

Circuits on the left side of this figure, which present the highest risk to system performance if there is an outage, will need to be **Fortified** and in some cases **Fractionalized** to harden circuits against future risks and reduced in circuit line miles to minimize the impact of outages, respectively.

These approaches are detailed further in the Resiliency Investments section of this plan.

Circuits in the middle and right side of this figure that do not have an outsized impact when there is an outage may also be Fractionalized, but will primarily be addressed through **Fusing**, **Forestry**, and **Fixing** to improve the expected performance of most circuits, and are detailed further in the Reliability Issues and Investments for LVD Lines and Forestry Line Clearing sections of this plan.

FIGURE 38
LVD CIRCUIT SAIDI



LVD Safety-Focused Issues and Investments

The **greatest public safety risk from the LVD system comes from downed wires**, usually following weather events. Energized downed wires are dangerous and, if contacted, cause injury or fatality.

To mitigate this risk, the Company works to repair downed wires as soon as possible and has procedures to guard downed wires until they can be fixed (emergency responders will also do this, and the MPSC rules provide that the Company must relieve emergency responders in a timely manner).

The investments planned as part of the following LVD asset subclasses reduce this risk by preventing outages, downed wires, and other contact with energized equipment:

- Standardizing the Company's system voltages **through Voltage Conversions** to mitigate the safety risk from ungrounded wires and allow for quicker recoveries from outages.
- Removing **Subsurface transformers** to improve employee safety, avoid potential public contact and environmental contamination.
- Modernizing legacy **secondary distribution assets**, to provide a safer and more resilient final service to many customers after the final transformer.

Legacy open wire secondary presents a particular safety issue in the event of a downed wire because they are not well-insulated, are not always easily accessible to crews, and usually located in higher population areas.

Voltage Conversions

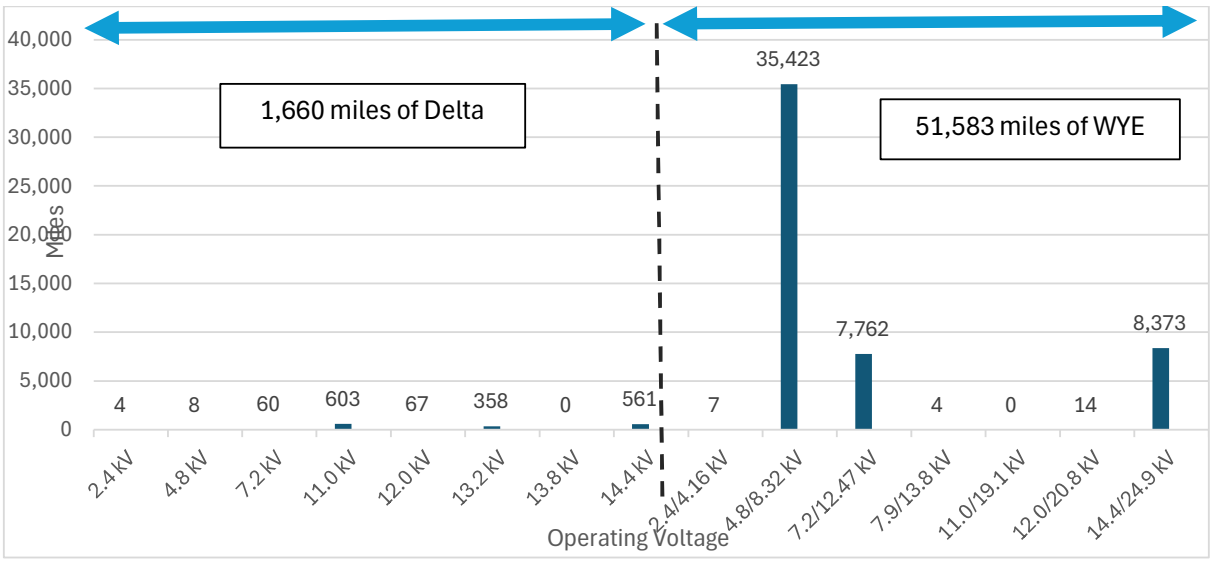
The Company's LVD system consists of 13 different voltages, a holdover from when the Company acquired smaller systems throughout its history.

Non-standard voltages restrict the Company's ability to install transfers between circuits and modernize the grid in a streamlined fashion because circuits of different voltages cannot be connected.

Figure 39 below, shows the Company's three standard voltages, which are 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV, along with the 10 remaining non-standard voltages and associated overhead line miles.

Figure 39

OVERHEAD PRIMARY LINE MILES BY VOLTAGE AND CONFIGURATION



While only a fraction of the overall system, the 1,660 miles of Delta are less safe to operate compared to a grounded wye system.

- Delta systems require two phase ground faults to be present before the phase protective device trips, which means a downed Delta wire will not trip a primary protective device until a second phase fault develops.

By converting non-standard components to one of the three standard voltages, **the Company will mitigate the safety risk from ungrounded wires and increase operational flexibility** by expanding the ability to transfer loads to reduce outage times.

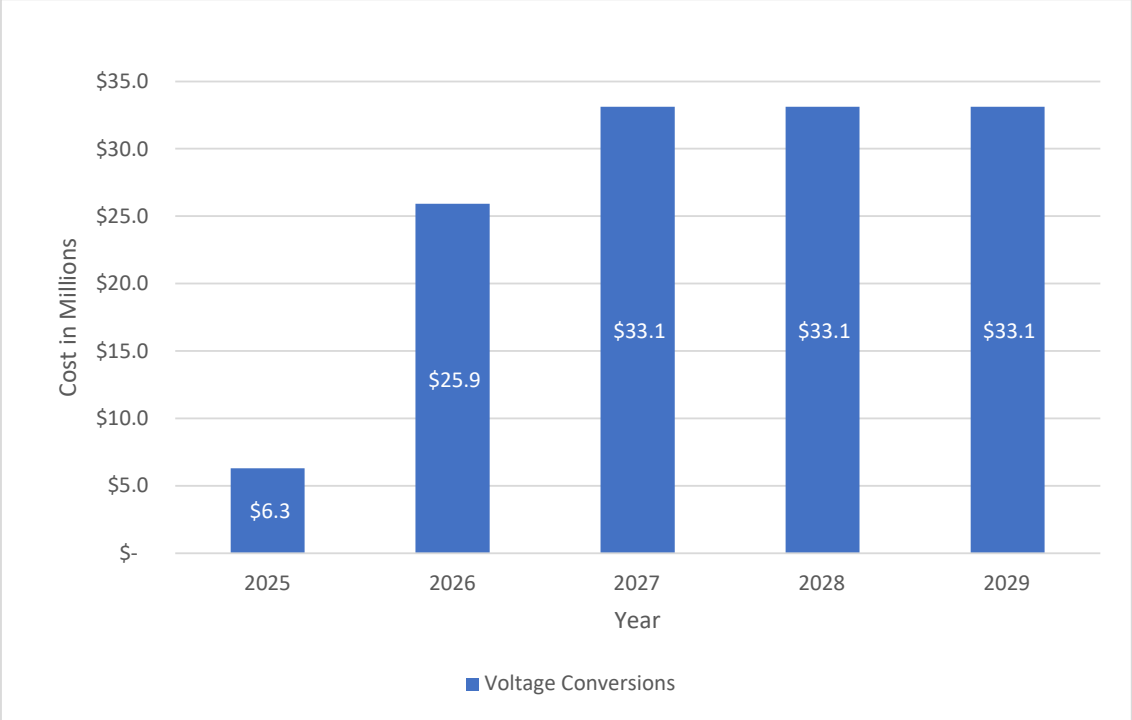
Additionally, voltage conversion will increase efficiency and reduce the operating costs through requiring lower levels of inventory to serve the variety of voltages.

The Company plans to invest $33 million per year over the next 10 years to convert at least 165 miles per year of non-standard voltage overhead lines, with an end goal of converting all non-standard voltages.

The next 5 years of spending for this plan is detailed in Figure 40 below.

Figure 40

VOLTAGE CONVERSIONS 5-YEAR INVESTMENT PLAN



Year	Miles of Nonstandard Voltage Converted
2025	33
2026	210
2027	268
2028	268
2029	268

Subsurface Transformers

Figure 41

FIELD VIEW OF SUBSURFACE TRANSFORMER



In 2023, the underground system had 159 of its original subsurface transformers, representing 0.15% of the transformers serving the underground system. At the end of 2024, there are 139 remaining.

While few in number and while not having a major impact on reliability, **subsurface transformers present a safety risk for Company employees, the public, the local environment, and grid reliability**.

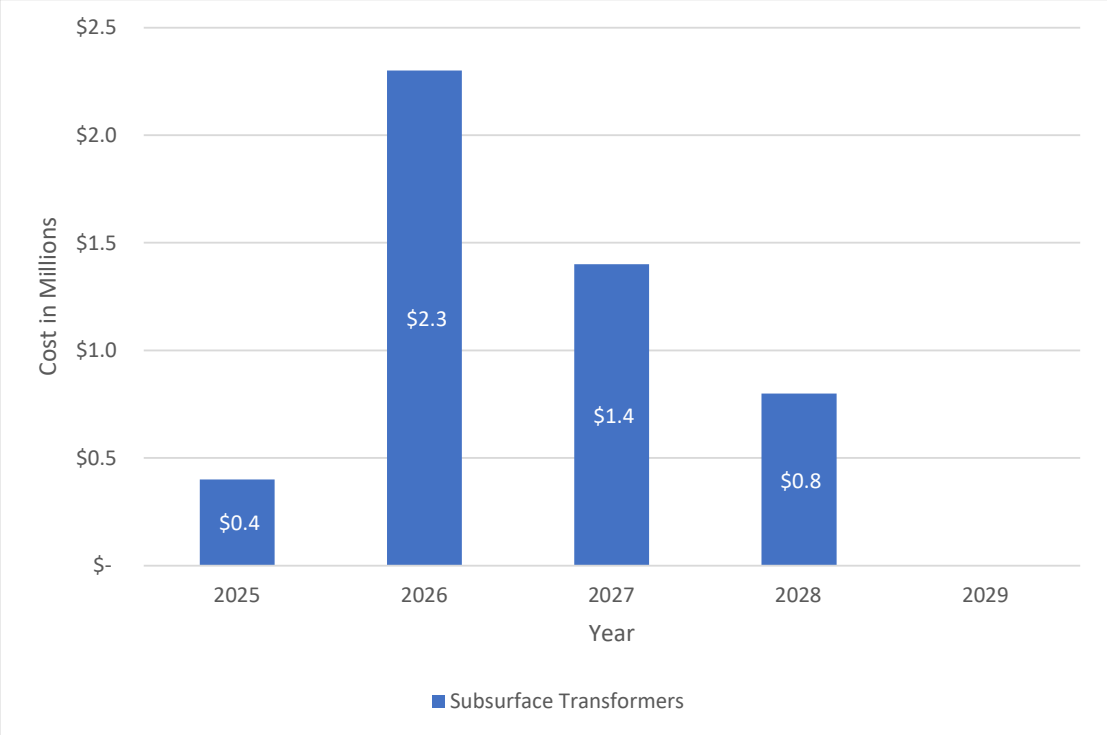
- Since these assets are located underground, Company employees have difficulty accessing and repairing them when they fail, leading to an outage lasting roughly four times longer compared to padmount transformers.
- The location makes it difficult for the public to recognize these transformers in the field, making it easier for them to come into contact with these transformers.
- Lastly, these transformers are more difficult to inspect when they do fail, making a subterrain oil leak more likely, contaminating nearby land and ecosystems.

To address this issue, the Company has begun proactively replacing all 159 subsurface transformers with padmount transformers, which are easier to inspect and repair. As of the end of 2024, there are 139 remaining on the system.

The 5-year investment plan is shown below.

Figure 42

SUBSURFACE TRANSFORMERS 5-YEAR INVESTMENT PLAN



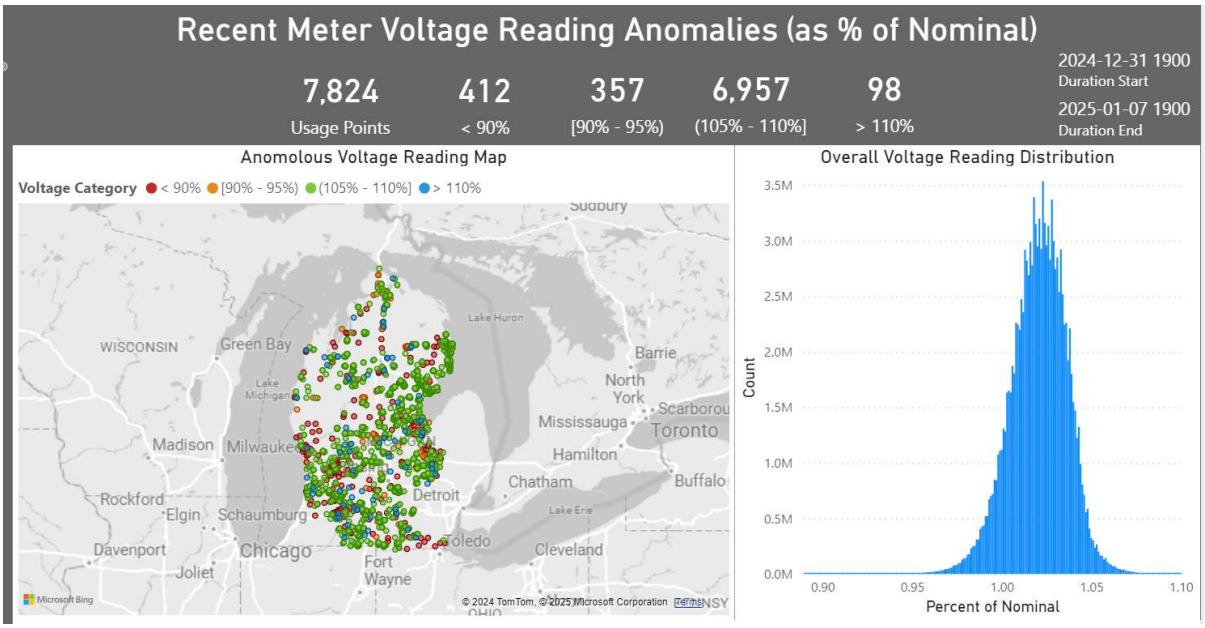
Year	Subsurface Transformers Replaced
2025	11
2026	40
2027	53
2028	35
2029	0

Meter Voltage Anomalies

The Company's AMI meters allow for continuous monitoring of customer service delivery point voltage levels. The criterion for acceptable voltage is outlined in Rule 702 of the MPSC Standards of Quality of Services, and in most cases is ±5% of nominal voltage. The vast majority (>99%) of service delivery points maintain this voltage level, as shown in Figure 43 below.

Figure 43

METER VOLTAGE ANOMALIES



As shown in the histogram in Figure 43, the majority of voltage anomalies are 5% to 10% above nominal voltage.

After several years of investigating and reactively correcting these anomalies as they arise and are reported by customers, there are three main causes of voltage anomalies:

- Low voltage (<95% nominal) is typically due to heavily loaded secondary and line transformers
- Moderately high voltage (between 105% and 110% nominal) is typically due to voltage regulation device issues
- More extreme (>110% nominal) high voltage typically is due to internally faulted but still energized line transformers. These internal faults result in the transformer turns ratio being altered, creating sustained high voltage on the load side of the transformer. Figure 44 below shows an example of this type of failure that requires replacement of the line transformer.

Figure 44

INTERNALLY FAULTED LINE TRANSFORMER



While the Company has been addressing meter voltage anomalies on a reactive basis as they are identified by customers, the Company is now planning to proactively address them, using AMI data to identify noncompliant locations.

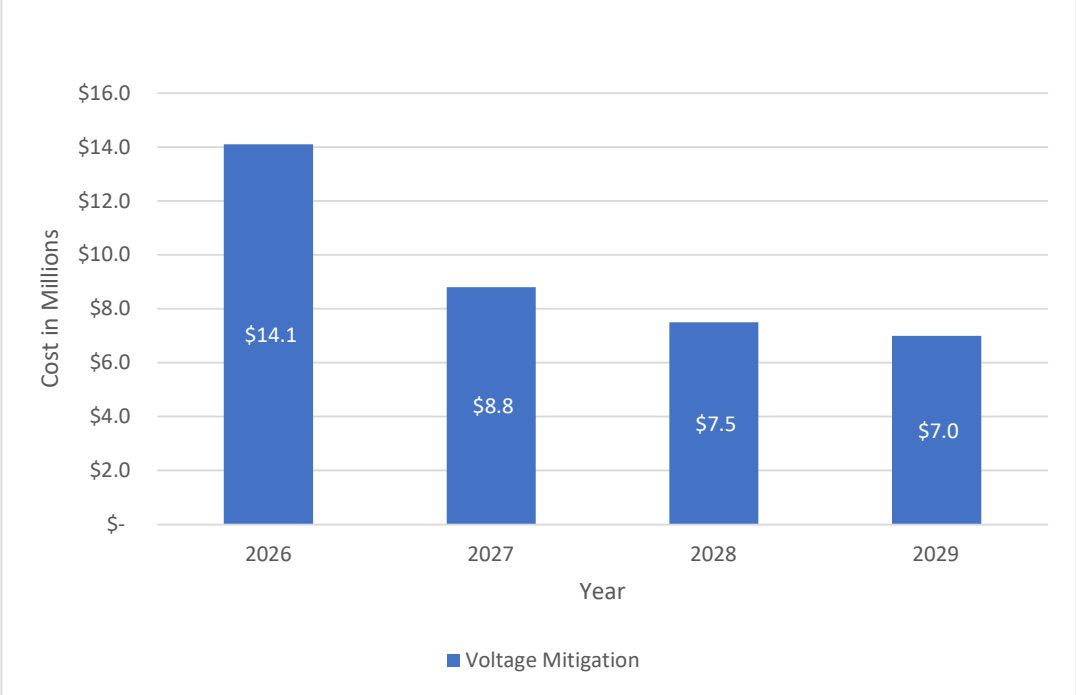
In many cases, particularly where voltage is low, AMI data should let the Company identify locations even before customers recognize that their voltage is out of compliance.

The Company projects that, over the next five years beginning in 2026, it will need to complete the work shown in Figure 45 to address meter voltage anomalies on the system.

FIGURE 45

METER VOLTAGE ANOMALIES 5-YEAR INVESTMENT PLAN

Year	Line Transformers Replaced	Regulator Mitigations	Low Voltage Mitigations (Secondary Miles)
2026	650	125	25
2027	300	100	15
2028	300	75	15
2029	300	50	15



Secondary Circuit Assets

Secondary circuit assets are located between the distribution transformer and customer meter. Repairs are more challenging than primary repairs for crews for various reasons.

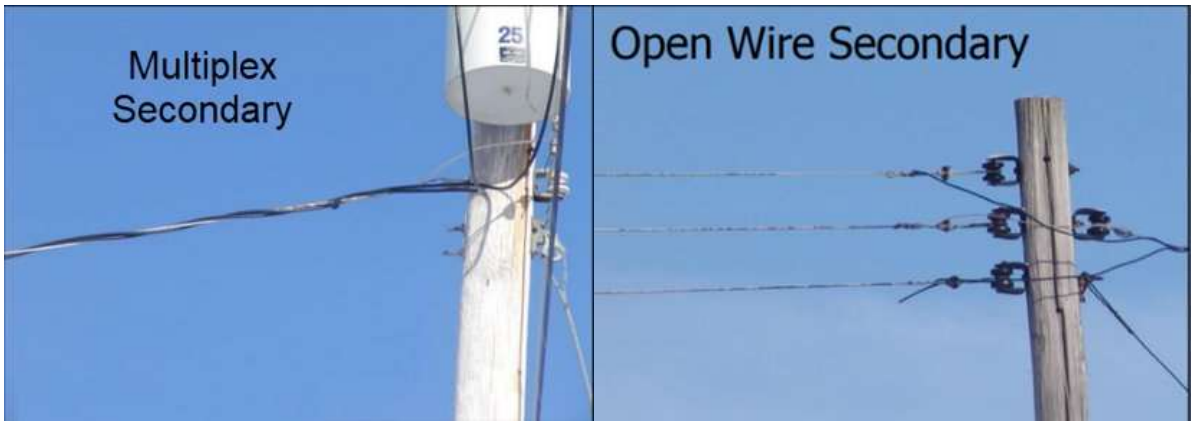
- In urban areas—in many cases in EJ communities—the secondary is typically located behind homes in backyards instead of roadside. When secondary is behind the home instead of roadside, it is more difficult to access with a bucket truck (e.g., along property lines with fences without an ally way) and may require Forestry assistance to access.

- Of the 31,000 miles of secondary on the Company's system, 27,000 miles are multiplex, and 4,000 miles are open wire. Examples of multiplex and open wire secondary are shown below in Figure 46.

Open wire secondary is more challenging to repair than multiplex secondary because breaks often occur mid-span, and if bucket truck access is not possible, repairs require splicing on the ground and then routing the conductor through trees.

- Much of the open wire secondary is nearing or at the end of its life, which causes the conductor to be brittle and not easily repaired.
- Open wire secondary is also more vulnerable to tree damage than multiplex. In general, the solution to issues with open wire secondary is to convert it to multiplex.
- Secondary outages occur at an average of 10 outages per day across the state and affect, on average, 3 customers per outage.

FIGURE 46
MULTIPLEX VS. OPEN WIRE SECONDARY



The factors that make secondary repairs more challenging contribute to higher average outage durations with an average duration of more than 10 hours. **These long response times present a risk to public safety, since wires are down for longer periods of time.**

These long duration, high frequency outages also cause the Company's line crews to spend more time, at a higher cost, to address emergent outages at the expense of planned work to proactively improve system reliability.

Outages overnight cause crews to have delayed start times, which further reduces the amount of planned work the Company can complete. They also drive costs higher as the repair work is done on overtime. Approximately 13% of secondary repairs are made during overnight hours.

The reliability and safety risks associated with secondary are particularly important for EJ communities.

- Approximately 18% of the Company's secondary in EJ communities is open wire. The long duration nature of secondary outages has a heightened impact on EJ communities, where customers are less likely to have back-up power generation, and experience financial and health impacts from long outages more acutely.
- Secondary in EJ communities tends to be in high population areas. This further increases the risks associated with downed wires.

A key benefit to secondary replacement is that it includes installing larger secondary conductors with more capacity, in anticipation of future electric vehicle loads and rooftop solar installations.

Installing larger secondary conductors will reduce the number of future upgrades required for our customers when they adopt new technologies.

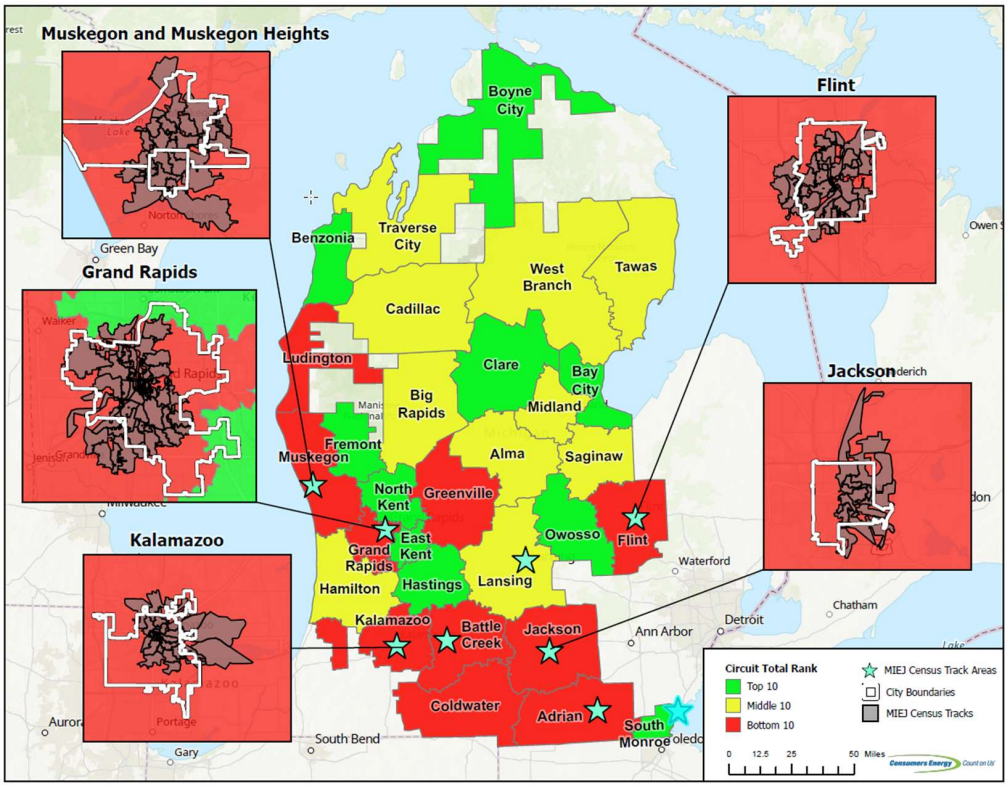
The Company measures secondary asset health through a combination of impacts to customers and number of interruptions.

In Figure 47 below, the Service Center regions with the worst performing secondary across the Company's service territory are highlighted in red.

As the map shows, many of the regions with the worst performing secondary contain high concentrations of urban areas and EJ communities. Focusing our investments in these areas will result in the greatest cost benefit for improving reliability while investing in EJ communities.

Figure 47

WORK HEADQUARTERS WITH MIEJ CENSUS TRACK



When open wire secondary is replaced with multiplex secondary, reliability increases.

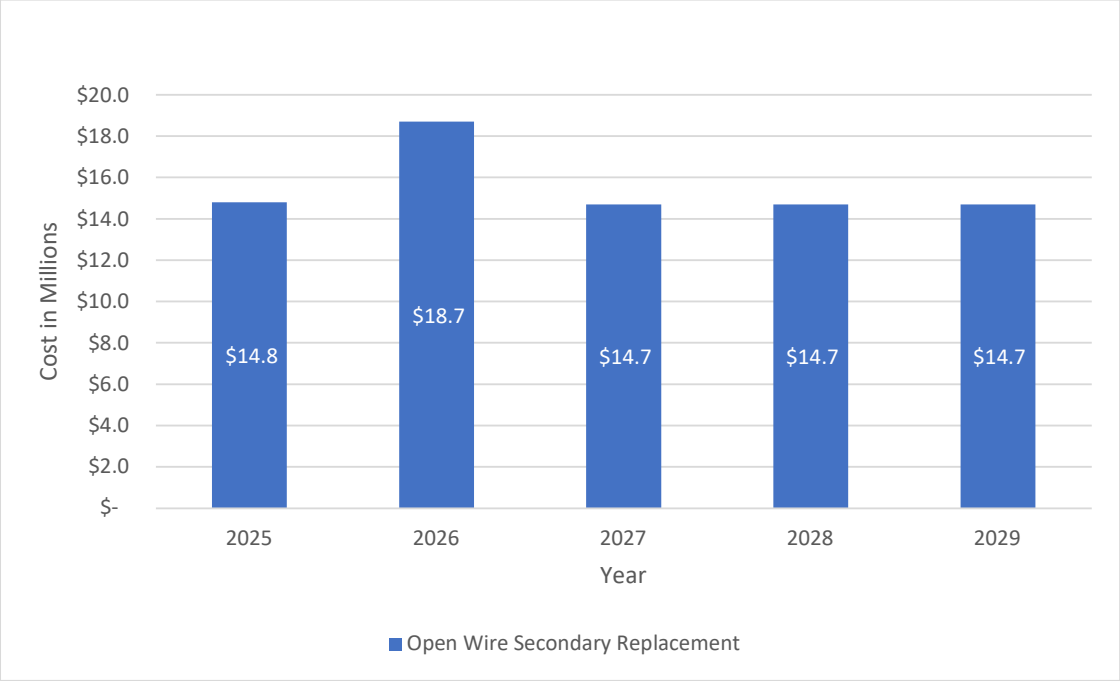
- Although the SAIDI impact of open wire secondary is not large, replacing open wire secondary is still beneficial. It reduces local outages, improves local CEMI and CELID metrics, facilitates employee training, and most importantly, reduces the risk of downed wires.

To address issues relating to open wire secondary, the Company is accelerating replacement of open wire secondary with a program of targeted replacements for the worst-performing circuits.

The Company plans to invest approximately $14.7 million per year over the next 10 years on the worst-performing secondary circuits in its territory, as detailed in Figure 48 below.

Figure 48

OPEN WIRE SECONDARY REPLACEMENT 5-YEAR INVESTMENT PLAN



Year	Miles of Open Wire Secondary Replacement
2025	50
2026	63
2027	50
2028	50
2029	50

Wildfire Risk Mitigation

As part of delivering safe and reliable electricity to customers, the Company must address the growing wildfire risk brought on by changing climate in Michigan[7].

Over the last decade, wildfires have grown in number and severity throughout the United States, and become a significant public health and safety concern. In the last 13 years, there have been more than 100 wildfires in the Lower Peninsula each year, burning more than 2,000 acres in seven of those 13 years and more than 2,000 acres in three of the last four years.[8]

Given these trends, the Company developed a wildfire risk mitigation plan for its electric territory. This plan is a separate document that is provided concurrently with this updated Reliability Roadmap in Case No. U-21870.

This plan describes the Company's approach to mitigate the risk of wildfires caused by or impacting electrical infrastructure and surrounding communities throughout Consumers Energy's service territory, with safety as the top priority.

It outlines the steps the Company is taking or plans to take to develop competencies, invest in system hardening, and expand existing programs such as line clearing to alleviate the pressure from increased wildfire risk, all to improve the safety of customers, communities, and employees.

This plan will continue to evolve as the Company learns more about wildfire risk in Michigan, new wildfire risk reduction strategies and technologies, and how changing weather patterns impact the region.

As part of its wildfire risk mitigation plan, the Company intends to:

- Understand the current and probable wildfire risk areas in our service territory through development and maturity of assessment tools.
- Implement mitigation solutions that balance the risk of wildfires with safe and reliable energy delivery.
- Leverage existing programs, such as line clearing, to deliver benefits beyond reliability and resiliency.
- Implement procedures to inform customers and communities of wildfire preparedness measures and communication protocols in the event of a wildfire risk event, i.e., *Red Flag Warnings*.
- Engage customers and communities in the ongoing development of the wildfire risk mitigation plan, particularly as it relates to ensuring customer safety and electric reliability.
- Continuously improve this plan by leveraging industry experts and peers and learning about and deploying best practices.

[7] Wildfire Weather: Analyzing the 50-year shift across America, May 2023 - www.climatecentral.com
[8] Michigan Department of Natural Resources - Fire Report Dashboard

Reliability Issues and Investments for LVD Lines

The Company makes planned investments in its LVD lines to improve reliability through the reduction of outage risks by:

- Identifying and mitigating problems with primary conductor, poles, and other supporting components through **Targeted Circuit Health Improvements** and addressing the worst-performing areas of the system.
- Replacing and upgrading deteriorated **LVD poles that** perform better in under extreme weather.
- Upgrading **overloaded components** to prevent overload-caused outages.
- Rejuvenating and replacing deteriorated **LVD Vintage underground cable**.
- Promoting safety, efficient operations, and aesthetics in the downtown areas of Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw through the **Metro system.**

The Company also works through its **Forestry Line Clearing Program** to mitigate tree-related outages, which are the biggest external risk factor for LVD Lines. (Forestry Line Clearing also addresses tree-related risk on HVD Lines.) Forestry work, which is largely O&M, is discussed in the **Forestry Line Clearing Program** section of this document.

Inspection and System Maintenance

The Company is reducing reliability and safety risks through inspection and maintenance programs recommended by the *IEEE*.

The Company is proposing the following schedule, shown below in Figure 49, based on good engineering practice to help identify and correct problems before they result in outages.

FIGURE 49
LVD O&M INSPECTION CADENCE

Inspection Task	Cadence	Components Checklist	Annual O&M Cost
LVD Line Inspections	2 Years	• Visual Inspection of pole and pole top components. • If a pole is suspected of failure perform test for strength.	$125K
Padmount Inspections	Significant Sample Annually	• Visual external safety inspection to identify if secure, holes or leaking.	$500K
Electronic Circuit Recloser	Remote Monitoring	• Monitor for any abnormality in performance and investigate for correction.	$400K
	4 years	• Replace battery and inspect reclosers without modems for any abnormality in performance and correct as abnormalities are identified.	$425K
Switched Capacitor Bank	Remote Monitoring	• Monitor for any abnormality in performance and investigate for correction.	$300K
Gang Operated Switches	3 Years	• Inspect and cycle the switch to ensure proper performance and correct as abnormalities are identified.	$450K
Disconnect Switches	4 Years	• Inspect, cycle and clean contacts to ensure proper performance and correct as abnormalities are identified.	$3.5M
Total			**$5.7M**

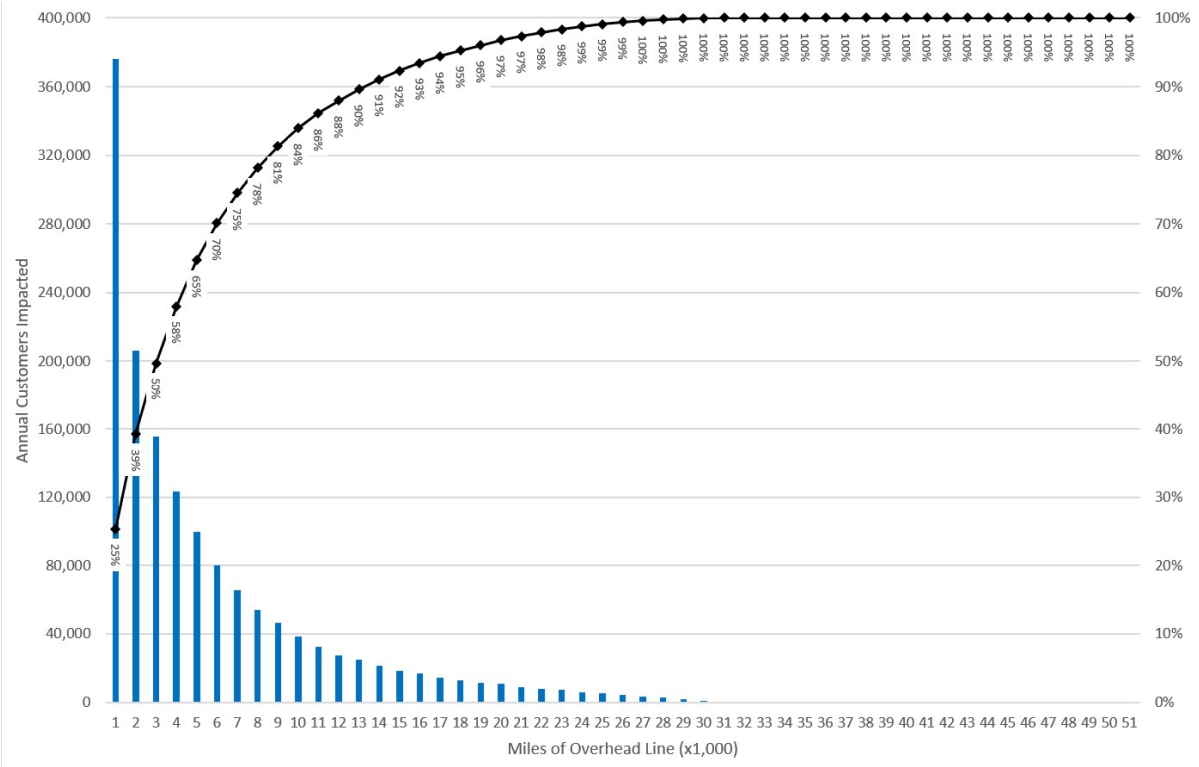
Zonal Health Assessments

In assessing LVD lines asset health, the Company has found that 91% of customer interruptions happen on just 25% of system miles, as shown in Figure 50.

Because of this, **the Company focuses on protective zones when assessing asset health and mitigating risk,** rather than on whole circuits. This enables the Company to focus on those parts of the system causing the most interruptions.

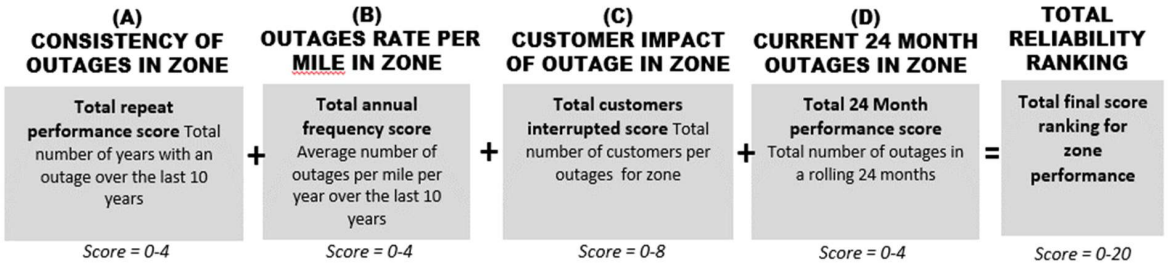
Furthermore, by focusing on the zones with the worst health, the Company can improve the reliability of customers downstream from the zone, not just the customers directly in the zone.

FIGURE 50
SYSTEM OVERHEAD MILES RANKED BY CUSTOMERS IMPACTED
(2015-2024)


Annual Customers Impacted
400,000
360,000
320,000
280,000
240,000
200,000
160,000
120,000
80,000
40,000
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
25% 39% 50% 58% 65% 70% 75% 78% 81% 84% 86% 88% 90% 91% 92% 93% 94% 95% 96% 97% 97% 98% 98% 99% 99% 99% 100% 100% 100

When the Company assesses zonal health, it uses a 20-point scale based on inputs from the Reliability Analytics Engine, with four data points driving the score. These are shown in Figure 51 below.

FIGURE 51
ZONAL HEALTH ASSESSMENT SCORING RUBRIC



- Of the Company's approximately 156,000 total zones, approximately 22,000 of those zones currently have a score; the remainder do not have a score, which means they have had no outage activity at all for at least two years.
- In other words, more than four-fifths of zones on the system are working as intended and do not need to be prioritized for any investment at all at this time.
- The Company has found that customer interruptions in a zone begin to increase exponentially once the total zonal health score exceeds 10 and gets particularly severe once the score exceeds 15.
- Of the approximately 22,000 zones that currently have a zonal health score, just over 7,800 of them have a score of 10 or higher, representing approximately 4.5% of the Company's total LVD system.

When the Company identifies poor-performing zones on LVD circuits, it designs a zonal health investment project to address one or more zones to resolve the problem.

- Zonal health investments can include replacing equipment at end of life, hardening existing assets, installing new system protection devices like fuses and reclosers, and improving the capability to isolate and transfer load. Taken together, all these actions reduce the probability of an outage.
- Zonal health investments have consistently delivered reliability benefits for the LVD system because these under-performing zones have been strategically selected for rehabilitation.

As shown in Figure 52 below, SAIDI improves substantially following the completion of zonal health investment projects.

FIGURE 52
SAIDI IMPROVEMENT FOLLOWING ZONAL HEALTH INVESTMENTS

Project Year	Zonal Projects	% Improvement Prior 3 years Post improvement
2017	147	51%
2018	138	57%
2019	151	66%
2020	146	71%
2021	249	62%
2022	1,394	40%
2023	2,884	28%
Weighted Average Improvement		**64%**

It is important to note that the "zonal projects" column includes fusing work in 2022 and 2023 in addition to more traditional zonal health improvement work, which is why the number of projects increases by so much.

Fusing projects do not necessarily reduce the number of outages on a circuit, but they do reduce the number of customers impacted by any particular outage. This impacts the before and after outage numbers in the figure, and therefore the calculated percentage improvement.

Please note that traditional zonal health improvement work delivers substantial outage reduction benefits, as shown in the data from 2021 and earlier.

In addition to zonal health investments, the Company also installs ATR loops on the LVD system to automatically restore power to customers when an outage occurs. This is described later in this report in the section on Resiliency Investments.

LVD Zonal Health Investment Plan

The Company plans to address all zones with scores of 10 or greater, since interruptions to customers begin increasing exponentially once the zonal health assessment score exceeds 10 out of 20. This will require targeted zonal health investment projects for each of these zones.

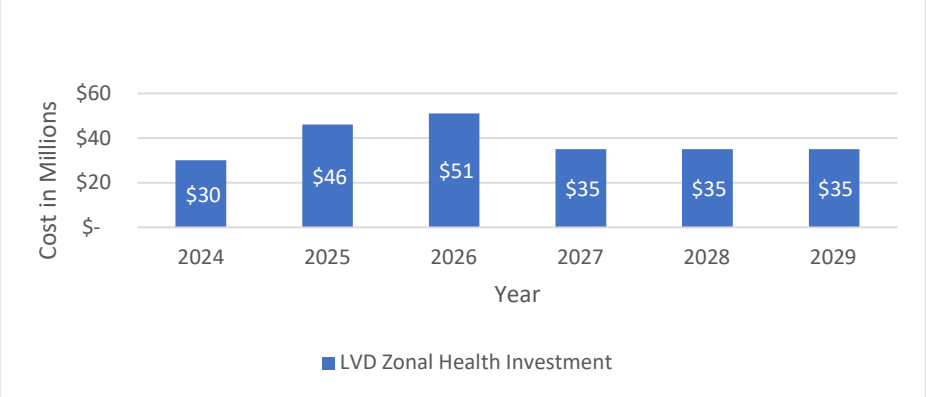
At present, the Company plans to address an average of 85 zones per year.

The Company will rank zones from worst to best by zonal score, and address zones in that order, periodically reprioritizing to ensure that the Company's workplan is continually targeting the worst-performing zones.

The 5-year investment plan for LVD zones is shown below in Figure 53.

Figure 53

LVD Zonal Health 5-Year Investment Plan



Year	LVD Zones Addressed
2025	110
2026	340
2027	85
2028	85
2029	85

LVD Pole Health Assessment

As noted earlier, the average age of an LVD pole is 40 years. Pole failures take roughly twice as long to replace compared to replacing damaged pole top equipment, such as pins or wood crossarms.

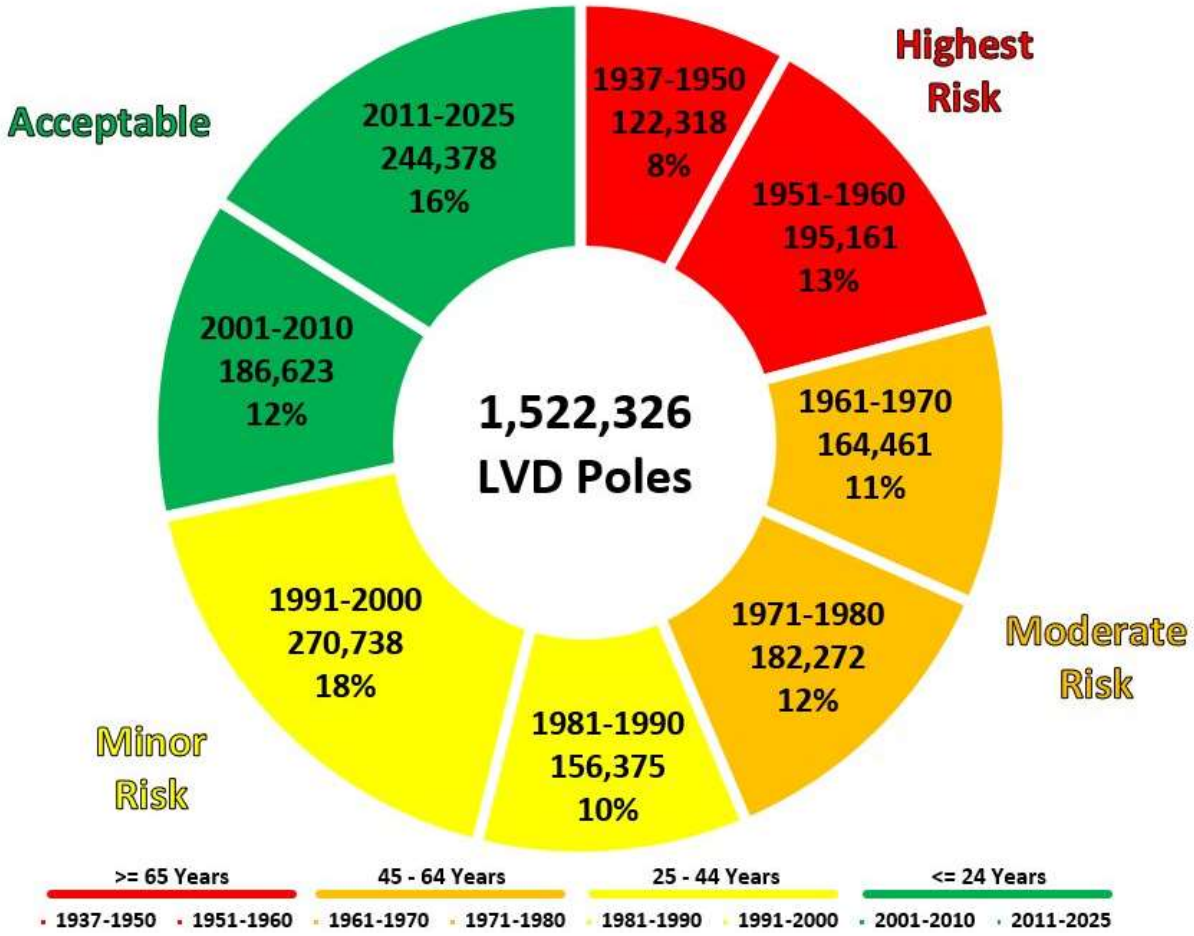
Additionally, underground facilities need to be located by an outside agency prior to digging for safety reasons. These locate requests can take up to three hours in an emergency.

According to *National Electric Safety Code* ("NESC") standards, if a pole deteriorates to below two-thirds of its original install state, it is classified as "rejected" meaning the pole is more vulnerable to failure in car-pole accidents or by high winds, ice, trees, or other external factors.

Figure 54 below shows the number of poles on the LVD system by the decade in which they were installed, with the corresponding risk level for each vintage. The Company expects that the highest risk poles have a >15% rejection rate, the moderate risk poles have a 10%-15% rejection rate, and the minor risk and acceptable poles have a <10% rejection rate.

Based on this information, the Company estimates that 10% of the system, or approximately 150,000 poles, would be classified as rejected.

FIGURE 54
NUMBER OF LVD POLES BY VINTAGE



The Company is working to reduce risk from poles by performing visual security inspections, and replacing the most urgent poles identified from the pole inspection program. The Company is also beginning a groundline inspection program to inspect all poles on a 12-year cycle.

To build a more resilient system while aligning with industry standards, the Company has changed the minimum standard pole classes to provide greater capacity for LVD overhead lines and a more reliable outcome for the future.

- The Company went from Class 6 to a Class 3 for our primary applications starting in 2021, which will increase capacity by nearly 200% as shown in Figure 55 below.

Figure 55

2023 NESC CODE[9]

No Significant Pole Deterioration as Noted in NESC Table 261-1			
NESC Grade C Construction - LVD - NESC 250C&D Load Factors			
Pole Size Minimum	No ICE, Max Wind Speed Prior to Failure (mph)	½ Inch Ice, Wind Speed Prior to Failure (mph)	1 Inch Ice, Wind Speed Prior to Failure (mph)
Class 6	109 mph	54 mph	39 mph
Class 5	116 mph	57 mph	43 mph
Class 4	129 mph	64 mph	49 mph
Class 3	141 mph	71 mph	54 mph
Class 2	157 mph	79 mph	60 mph
Class 1	170 mph	86 mph	67 mph

The largest impact of this change is when the Company replaces existing poles in the field that failed during storm restoration and were originally sized using smaller pole class minimums, or for new overhead line construction.

Based on the larger number of LVD distribution lines, it is estimated that 2-3% of our overhead LVD distribution system is replaced or newly installed with this new standard each year.

Additionally, poles are regularly replaced as a component of targeted zone improvement projects, plus other programs like Asset Relocations and New Business.

LVD Pole Investment Plan

Starting in 2025, the Company will initiate a groundline inspection program to identify and replace all rejected poles on a 12-year pole inspection cycle and inspect 125,000 primary and secondary poles each year.

- The Company will inspect a minimum of 50,000 poles in 2025, though if time and capabilities permit, up to 125,000 poles may be inspected. The Company plans to ramp up to where it consistently performs 125,000 pole inspections per year.
- Using the historical 10% rejection rate, the Company expects approximately 12,500 poles will need replacement each year, at least once the Company hits its full stride of performing 125,000 annual inspections. The inspections will cost $3 million annually in O&M spending.
- During the Company's regular 2-year circuit inspection cycle, the Company will continue to visually inspect poles and replace them as needed.

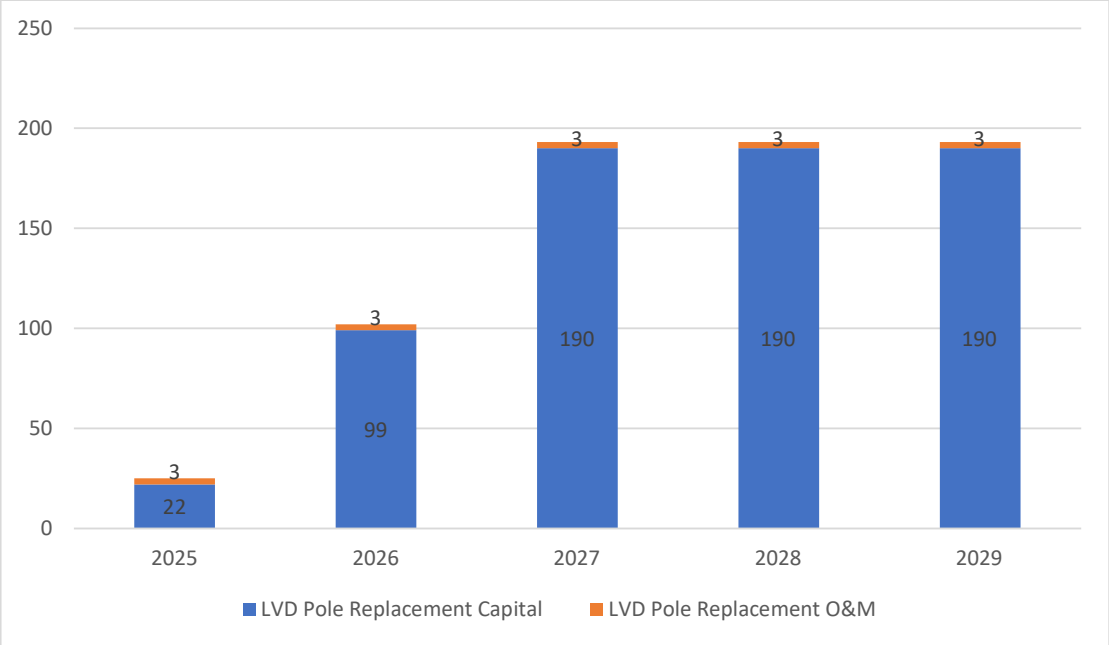
[9] 2023 NESC, linear analysis, 1/0 ASCR 3 phase conductor with #4 ACSR Neutral, 350-foot spans, 45-foot pole lengths.

Altogether, this replacement plan based on groundline inspections will identify and replace approximately 12,500 poles annually and will cost approximately $190 million in capital spending per year.

The investment plan for LVD poles is shown below in Figure 56.

Figure 56

LVD POLES INVESTMENT PLAN ($000S)



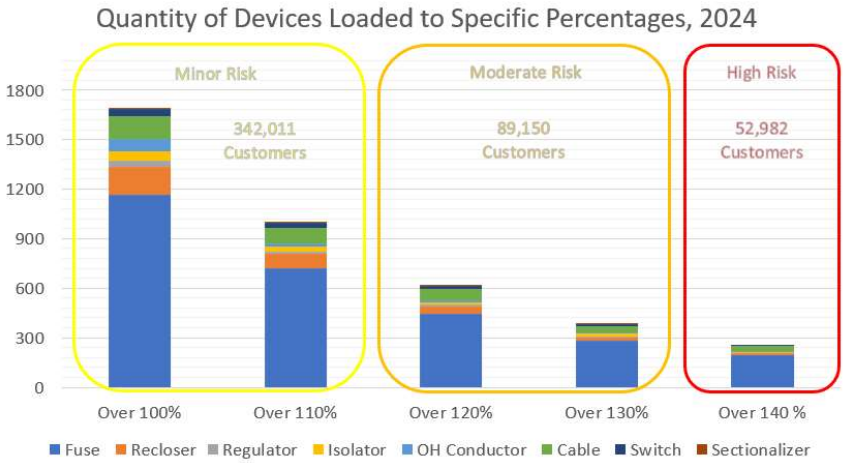
Year	LVD Poles Replaced
2025	2,300
2026	9,700
2027	12,500
2028	12,500
2029	12,500

LVD Overload Risk Reduction

The LVD system also faces risks related to components overloading driven by local load growth.

When a component fails due to being overloaded, it results in an unplanned outage. These unplanned outages generally take longer to restore than planned outages, increasing SAIDI. The risks to customers due to component overloads are shown in Figure 57 below.

FIGURE 57
QUANTITY OF COMPONENTS LOADED TO SPECIFIC PERCENTAGES, SUMMER 2024



In general, individual components can withstand loading to greater than 100% of their rating for relatively short periods, such as a few hours on a hot summer day, but if overloaded too long or too frequently, they begin to deteriorate, introducing the risk of overload-caused customer outages.

Any component has a loading at which it will absolutely fail; these vary by component type, but the Company classifies components at the highest risk if they are projected to exceed 140% loading.

Components in the medium and high-risk categories may be able to continue operating normally if they are not regularly loaded past the 100%-130% range, as the components are designed to operate with that loading for short periods. However, those components still face risk because a modest increase in load, such as from an increase in EV penetration nearby, could quickly load those assets to 140%.

Ideally, the Company's investment plan will address any components that are loaded higher than 100% in order to fully mitigate the risks of overloads and eliminate overload-caused outages on the system

Of the overload-related risks on the LVD system, **isolators present the highest risk** because they are complex to replace, stock is limited, and outages tend to be for extended durations.

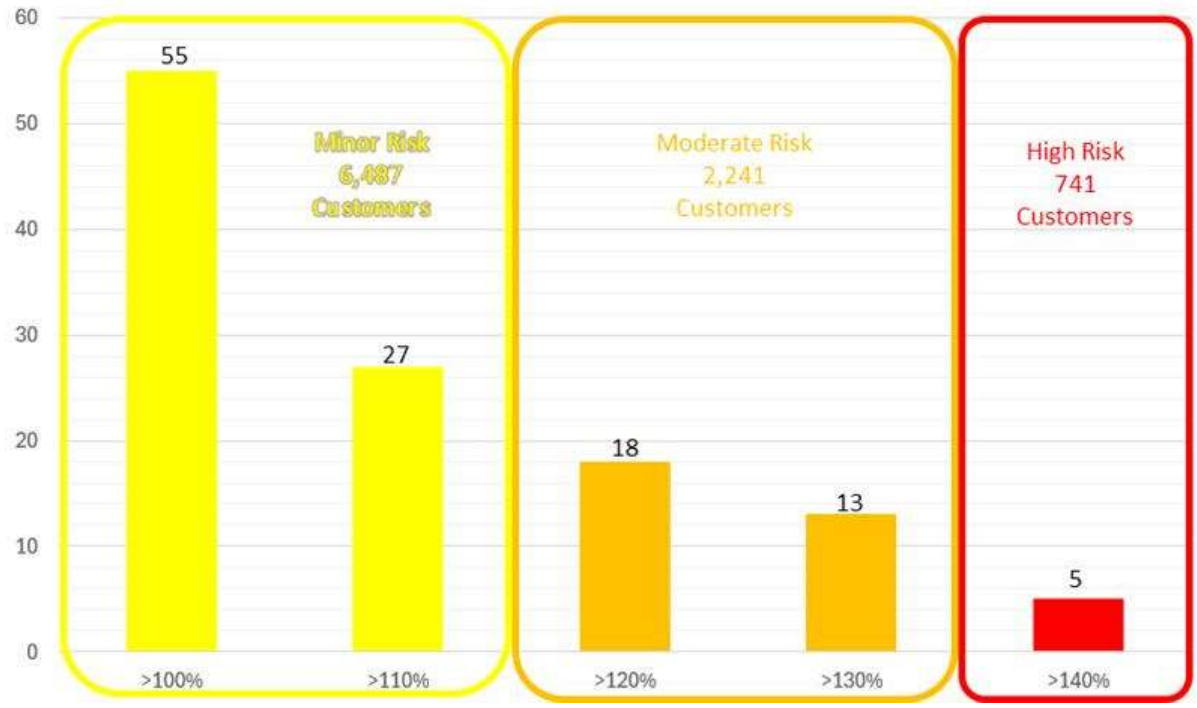
- Isolators are a specific type of transformer used to convert one primary voltage to another primary voltage.
- If an isolator fails due to an overload, it can create an extended duration outage.
- For comparison, a failed fuse can be replaced very quickly by crews throughout the state, which all maintain a sufficient inventory of fuses.

The number of isolators at risk is shown in Figure 58 below. Summer 2024 load data show there were 9,469 customers at Medium Risk level or greater of experiencing an outage due to overloaded isolators.

The Company intends to address overloaded isolators on the grid over the next 10 years to mitigate this risk to customers.

FIGURE 58

QUANTITY OF ISOLATORS LOADED TO SPECIFIC PERCENTAGES, SUMMER 2024



In addition to replacing overloaded isolators, the Company is replacing other overloaded components through its *LVD Lines Capacity Investment* subprogram, prioritizing projects based on the projected overload for the specific component and on a dollar-per-customer impacted basis.

The Company develops project proposals once components get loaded above the levels identified in Figure 59 below.

FIGURE 59

LOADING CRITERIA FOR OVERLOAD RISK REDUCTION

Device	Loading Criteria
Conductor	100%
Fuse	130%
Hydraulic Recloser	100%
Electronic Recloser	100%
Regulator/Booster	100%
Isolator	100%

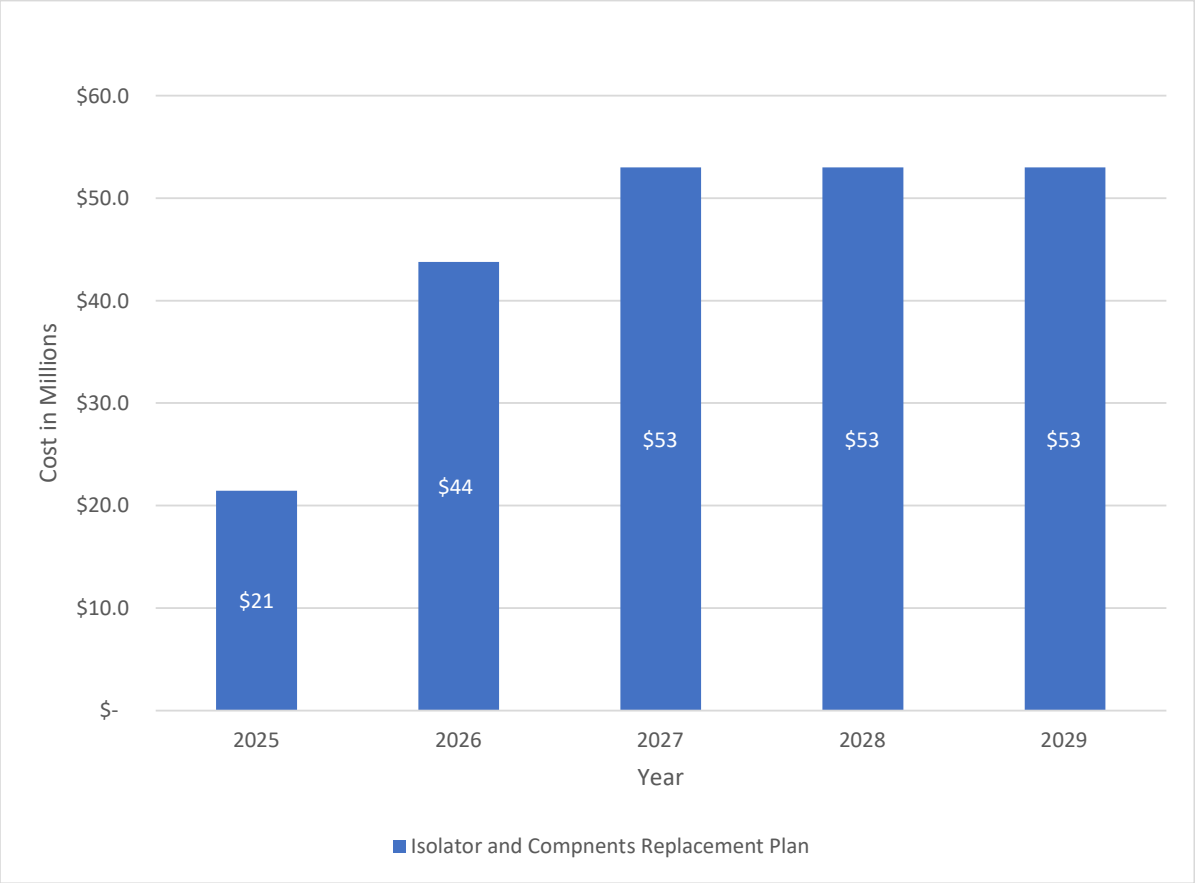
LVD Overload Risk Reduction Investment Plan

The Company will address all the isolators and other components currently loaded at or above the component-specific planning criteria.

The 5-year investment plan for LVD Overload Risk Reduction is in Figure 60 below.

FIGURE 60

LVD OVERLOAD RISK REDUCTION INVESTMENT PLAN



Year	Isolators Replaced	Components Replaced
2025	6	40
2026	8	52
2027	11	68
2028	10	67
2029	9	66

As discussed in the Challenges from Customer Technology Adoption section, load-impacting technology adoption could greatly exceed present levels, depending on consumer behavior, leading the Company to anticipate where customer adoption is most likely.

Specific to EVs, the Company has completed studies to determine where residential EV charging is likely to occur by examining the likelihood of a customer having an EV based on several factors including income level, and customer proximity to another EV. Based on this user profile, the Company predicts the circuits with the highest density of EV adoption over the next 4 years and will continue to re-evaluate further in the coming years.

While historically EV adoption has been in higher income areas, the Company expects to see increasing adoption across all segments, given developments such as the used EV tax credit, the increasing range of EVs and low battery degradation over time, and more EV models coming to market in general.

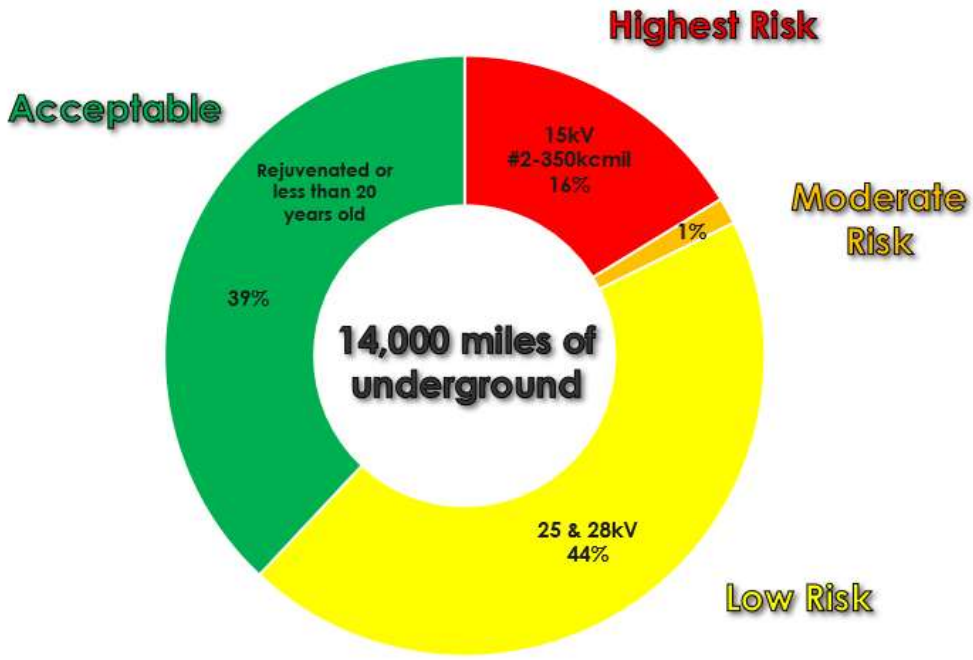
LVD Vintage Underground Cable

There are unique risks applicable to the underground primary system. While underground cable has historically lasted beyond its expected lifespan, vintage underground cable does present a heightened risk of failure.

- Out of a total of approximately 14,000 miles of underground primary cable (that equates to 9,500 system line miles), the Company has an estimated 2,500 miles of 15 kV underground cable dating to before the 1980s.

Figure 61

LVD Vintage Underground Cable Risk



- As this underground cable ages, the insulating material begins to degrade, reducing the remaining service life of the cable. This at-risk cable is also unjacketed, leaving the neutral conductors exposed to accelerated deterioration from direct exposure to external elements, such as soil and moisture.

The Company has recently begun using cable injection to rejuvenate cable, initially rolling this approach out in the Grand Rapids and Flint communities.

Cable Rejuvenation is *the process of taking a cable out of service, performing neutral and air flow testing, injecting a fluid like insulation that solidifies over time, and then putting the cable back into service,* all **at a lower cost than replacing the cable with new**.

- Any cable that fails the testing portion of the process gets replaced with new, jacketed cable.
- Approximately 2,300 miles of the 2,500 miles is smaller cable serving residential subdivisions and small commercial businesses and is eligible for cable rejuvenation.

A third-party contractor performs cable rejuvenation work, and it is most cost-effective to have this contractor complete all work in one area before moving on to other parts of the system. Therefore, the Company has targeted the work in only two communities at this point—Grand Rapids and Flint, with projects planned additionally in the Traverse City area in 2025.

The Company plans to continue targeted 15 kV underground cable rejuvenation; prioritization is based on which underground zones have the worst zonal health scores as explained earlier in the LVD Zonal Health Investment Plan section. Additionally, project selection considers feedback from the Company's electric crews who provide insight into repetitive repairs or field conditions.

Cable that is not eligible for cable rejuvenation, whether because of size or insulation properties, requires additional funding for replacement as it also begins to approach end-of-life expectancy. Thus, as insulation properties of underground cables have improved due to advances in technology and manufacturing capabilities, the ineligible cable must be replaced instead of rejuvenated.

In addition to vintage underground cable rejuvenation, **the Company is planning an aggressive program to convert overhead lines to underground** to mitigate the risks from severe weather, and dramatically improve the resiliency of its electric grid. This program and its associated costs and benefits are detailed in the Resiliency Investments section of this report.

LVD Vintage Underground Primary Investment Plan

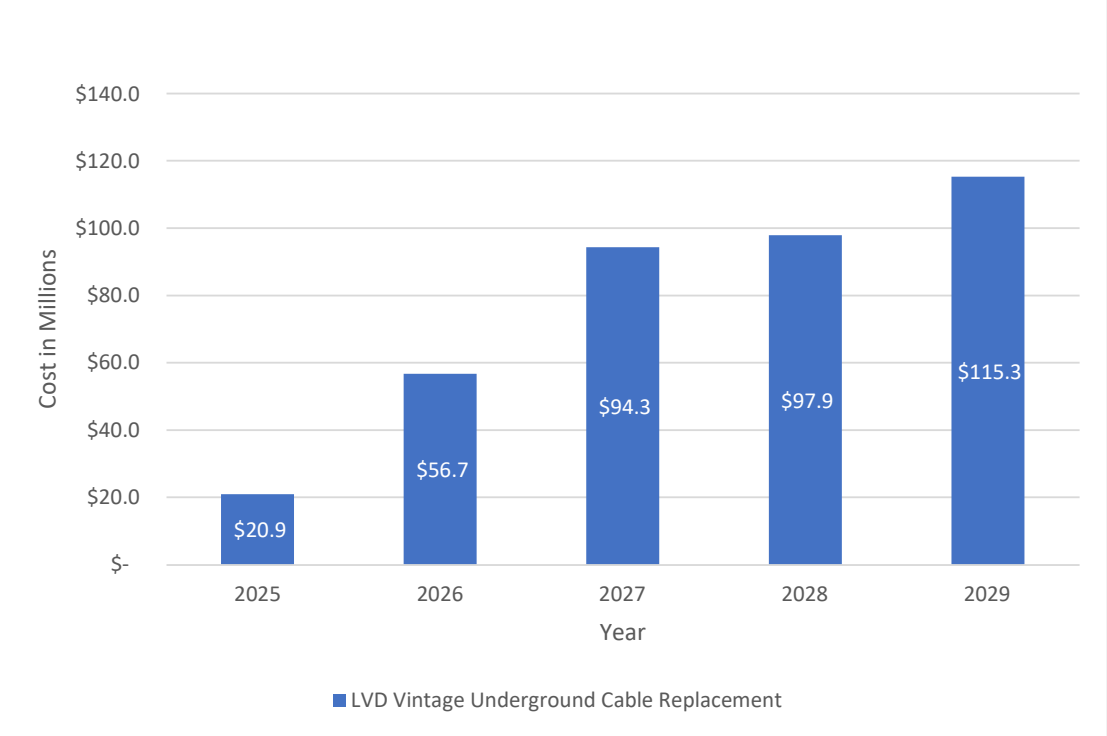
The Company will address all the 15 kV cable installed between the 1960s and 1980s, at a cost of $885 million over 9 years, beginning in 2025.

The program will ramp up each year until reaching a peak in 2031, then ramp back down through 2033 as the final cable replacements are completed. Near the completion of the program, the Company will evaluate the state of the rest of the underground system to determine the appropriate solution for the next highest risk cables.

The 5-year investment plan for LVD Vintage Underground Primary is shown below in Figure 62.

Figure 62

LVD VINTAGE UNDERGROUND PRIMARY 5-YEAR INVESTMENT PLAN



Year	Miles of Vintage Underground Cable Rejuvenated or Replaced
2025	51
2026	136
2027	226
2028	234
2029	276

Resiliency Investments

The increasing frequency of major and extreme interruption events due to severe weather has increased the Company's focus on ways to mitigate major weather events through resiliency investment.

Resiliency is defined as the *ability of the system to withstand a major event—particularly, a large or extreme storm—and the ability of the system to recover from a major event where damage occurs, minimizing the needed restoration and repair time.*

Reliability is defined as the *ability of the system to withstand normal variation and continue serving customers predictably*.

Resiliency and reliability are related.

- While *reliability* focuses on the typical days of the year, when conditions are normal, *resiliency* actions are focused on the much less frequent large or extreme storms. A resilient electric system yields reliable customer service by withstanding these extreme storms.

The following investment categories represent the Company's forward-looking investment in the grid to enable it to better withstand these extreme events, and to facilitate improved restoration times after these types of events occur.

LVD Undergrounding

The radial configuration of the LVD system and the proximity of large parts of the system to trees and other weather impacts necessitates additional investments to harden the LVD system to improve resiliency.

For one component of this, the Company has started to expand its underground system, strategically converting parts of existing overhead circuits to underground.

- Research conducted by peer utilities, most notably WEC Energy Group, has found that **undergrounding improves circuit performance by 90% or more,** as lines are no longer exposed to trees and other weather impacts.
- The Company estimates that **the cost to customers of undergrounding is comparable** to other means of hardening against trees and other weather impacts, such as by installing aerial spacer cable or tree wire.

The Company completed converting approximately 10 miles of overhead lines to underground in 2024 and early 2025, as approved in Electric Rate Case No. U-21389. This work was based on specific selection criteria. Following pilot completion, the Company retained most of its pilot selection criteria, but made adjustments to others, and is now using the following criteria going forward:

- Are single-phase sections of the system
- Have at least one outage in the last 24 months
- Serve between 10 and 200 customers
- Are operated at one of the three standard voltages
- Do not have other project work planned to enhance reliability
- Recent history of significant tree and weather-related outages
- Would have capacity available to account for future load growth

The Company plans to continue using these selection criteria to select undergrounding projects going forward.

Single-phase sections will have a lower conversion cost. Lines with at least one outage in the last 24 months were selected to provide more immediate benefit.

Limiting the customers served by the zone to between 10 and 200 ensures the project provides benefits to more than a few customers, while limiting the impact of any future outage on the underground facilities.

Underground conversion of only the three standard voltages ensures that additional costs are neither initially incurred on the additional equipment to accommodate delta configurations nor the conversion cost to a standard voltage later.

Similarly, selecting zones that are not considered for another reliability project avoids duplication of efforts. Underground conversion is considered an alternative when reliability projects are developed for targeted circuit improvement work.

Lines with recent history of significant tree and weather-related outages were selected to improve customer experience.

Actual costs and lessons learned from the undergrounding pilot has informed how the Company scales up its undergrounding work to ensure scaling the program will be successful.

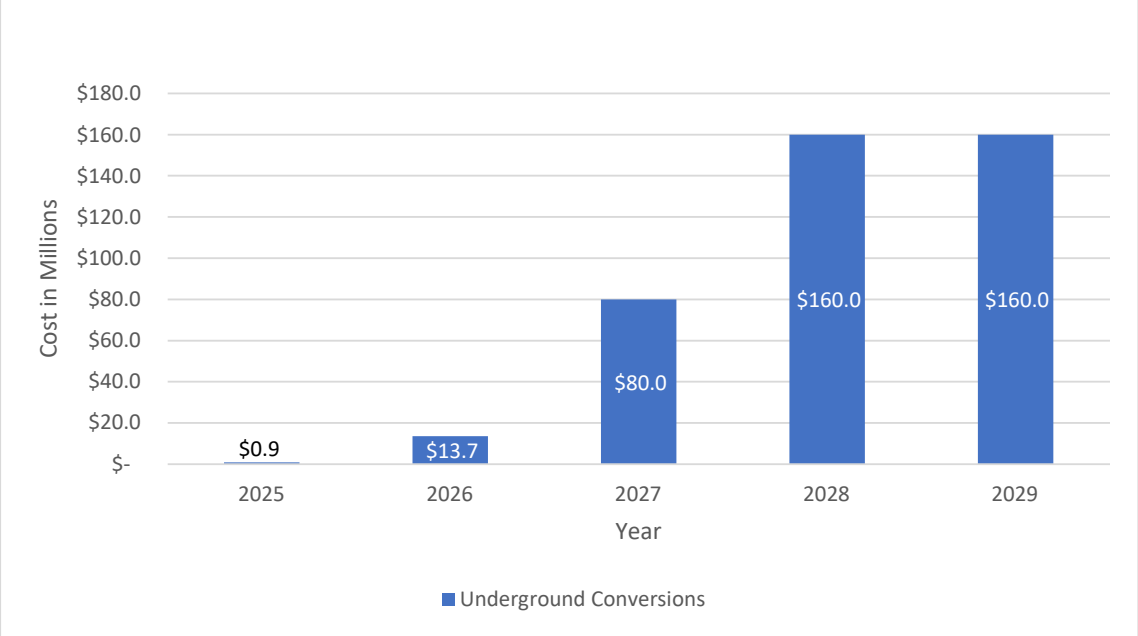
- The Company is planning to ramp up undergrounding work to 400 miles of line annually. Future analyses will take place as the program progresses to determine if the scale of the program should be reduced or increased. Ultimately, approximately 3,200 miles of the LVD system may be evaluated for undergrounding based on the criteria listed above.
- In identifying circuits for undergrounding, the Company is considering whether circuits serve EJ communities, given that these communities are more vulnerable in the event they experience a long outage following a catastrophic storm.

The projected cost for this work is identified below in Figure 63, with the in the projects to begin again in 2026, and full annual capacity of the undergrounding work beginning in 2028. With only 16% of primary lines currently undergrounded, the Company has a much larger exposure to the elements than its regional and Michigan peers, who average 25% of their systems undergrounded.

Expanded, strategic underground conversion of more of the Company's system is imperative to bring the Company's system in line with its peers and thereby improve reliability and resiliency for customers.

Figure 63

UNDERGROUND CONVERSIONS 5-YEAR INVESTMENT PLAN



Year	Underground Conversion Miles
2025	1
2026	34
2027	200
2028	400
2029	400

Fractionalization

On average the Company's LVD circuits are 30 miles with an average of 1,045 customers. Circuits with mileage exceeding the average exposes our customers to a much higher risk of weather-related outages.

Fractionalization, described earlier in the Five Fundamentals Approach, is another approach used by the Company to improve resiliency on the LVD system and involves **segmenting existing LVD circuits into smaller sections with fewer customers.**

- At present, this work takes place in substations, adding new transformer banks and circuit exits so that more circuits with fewer customers can be served from that substation. **This reduces the number of customers affected when there is an outage on a given circuit.**
- Fractionalization also provides more opportunities for load switching if an outage occurs, allowing for improved fault isolation and faster restoration of customers.
- Additionally, fractionalization results in fewer line miles for line workers to patrol and repair, further reducing outage times.

In the near term, the Company is primarily focusing fractionalization on circuits in the top 3% of customer count, and overhead line exposure; circuits in this top 3% serve more than 2,400 customers or have more than 90 miles of overhead lines as shown below in Figure 64, with the 5-year investment plans shown in Figure 65.

Figure 64

CIRCUITS RANKED BY CUSTOMER COUNT

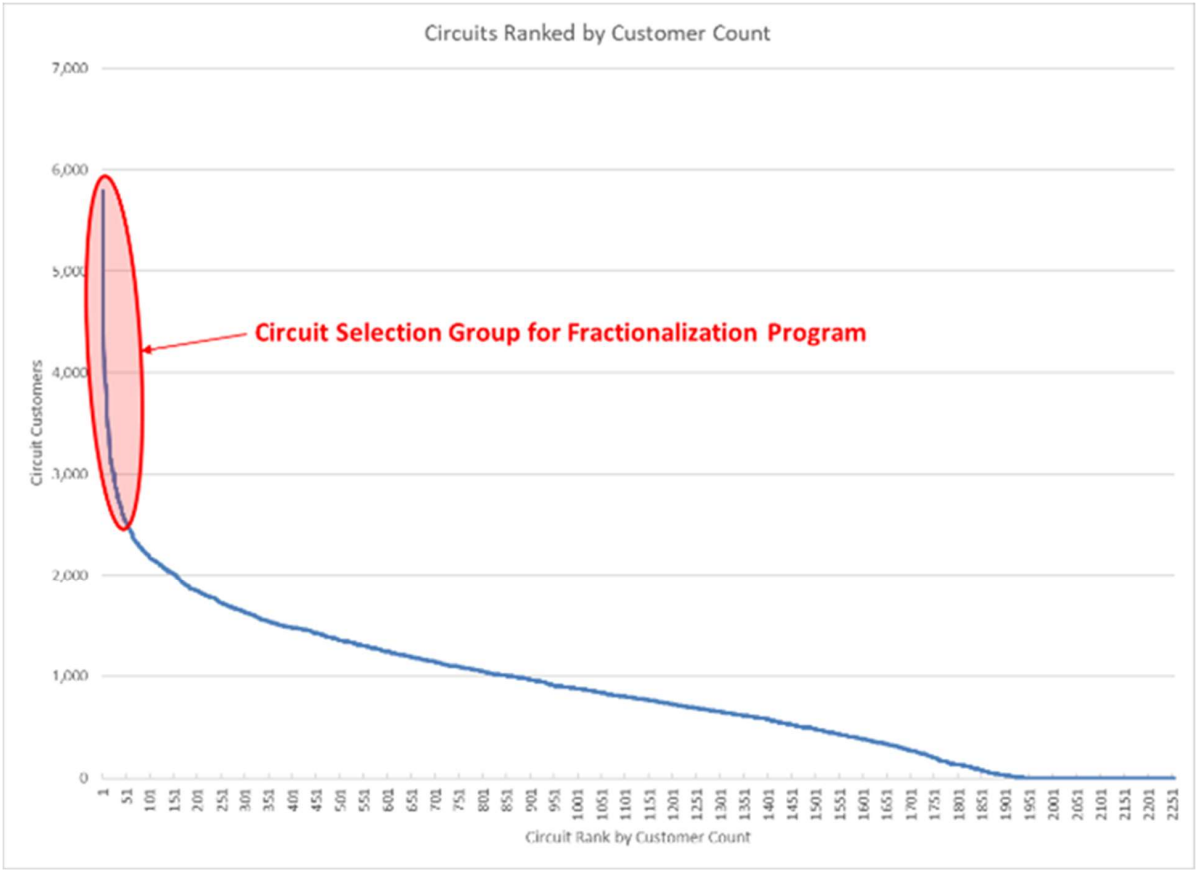
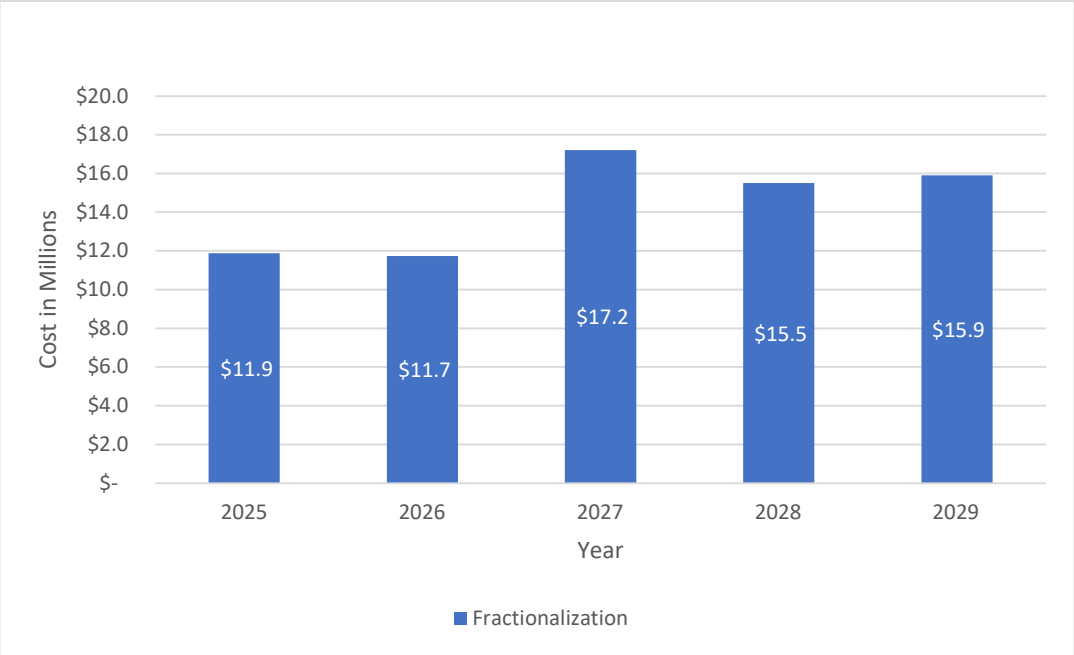


Figure 65

FRACTIONALIZATION 5-YEAR INVESTMENT PLAN



Year	Circuits Fractionalized
2025	6
2026	4
2027	5
2028	5
2029	5

Automatic Transfer Recloser (ATR) Loops

ATR loops have been an integral part of the Company's resiliency plan over the last decade.

Deploying ATR devices on adjacent LVD circuits enables **automatic transfer of customers if an outage occurs. This reduces customer outages and improves system reliability** by isolating a faulted section of a circuit.

- As of March 2025, there are 174 loops in service throughout the state.
- In 2024 alone, there were 138 instances in which an ATR loop operated, avoiding 21.9 million customer outage minutes, and preventing over 77,000 customers from experiencing an outage.
- Over the next five years, the Company plans to deploy between 25-35 additional loops annually to enhance automation on the grid and increase reliability savings.

As the ATR loop deployment matures, the Company is employing new, complex planning techniques to maximize benefits.

Currently, the Company is using "load limited" and "mutually exclusive" loops to enable ATRs, and to get the most out of the distribution system's capacity to avoid costly equipment upgrades, while still achieving significant automation benefit.

Previously, the Company may have ruled out an ATR solution for circuits where peak load conditions would exceed the equipment's thermal or loading ratings.

- Using ADMS, the Company can create real-time alerts that inform system operators when a circuit is approaching its peak load. Loops on these types of circuits are called "load limited."

Similarly, the Company has expanded the ATR loop selection criteria to include circuits fed from the same substation as an existing loop.

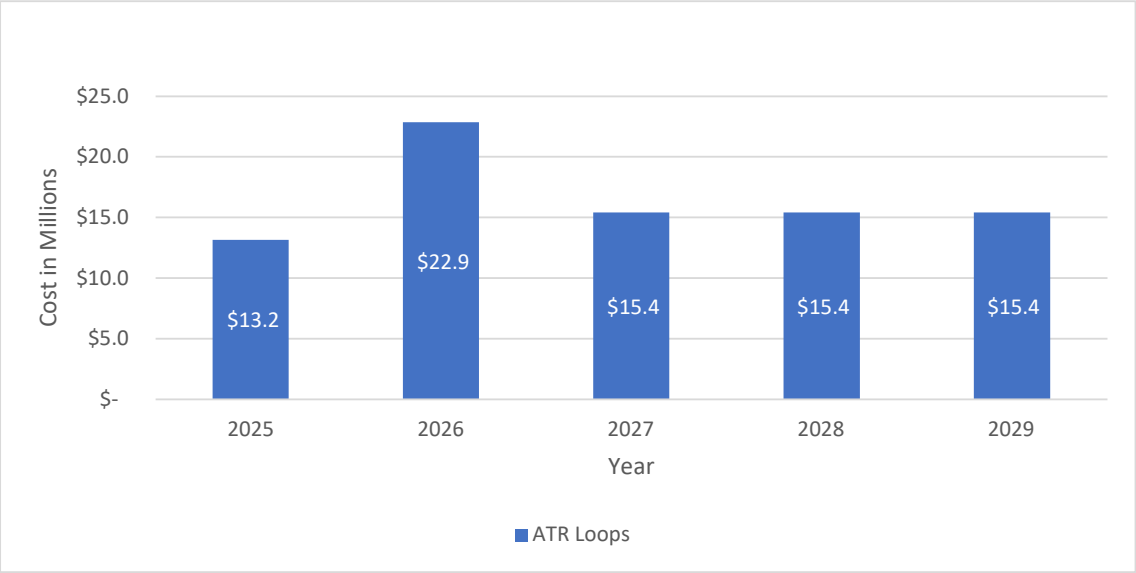
- To avoid overloading a substation transformer, alerts have been set up to notify operators when one of these mutual-substation loops has operated. These alerts trigger established processes for the operator to remotely disable loop scheme capability. Loops on these circuits are called "mutually exclusive."

These "load limited" and "mutually exclusive" loops allow for more circuits to be considered in the selection process, and as a result the Company can increase the achievable benefits from this investment category.

The ATR loops 5-year investment plan is shown below in Figure 66.

Figure 66

ATR LOOPS 5-YEAR INVESTMENT PLAN



Year	ATR Loops Installed Plan
2025	30
2026	44
2027	30
2028	30
2029	30

Other LVD Investment Areas

LVD Transformers

What Transformers Do

Distribution transformers convert voltage levels to enable customers to use standard equipment in their household or business.

- Within the overall category of LVD transformers, *isolators* are a specific type of transformer used to convert one primary voltage to another primary voltage.
- *Regulators* are a special transformer that ensure primary voltage remains in the desired range for reliable end-of line-voltage for customers.

In all, distribution transformers provide safe and reliable service to new and existing customers at an acceptable, reliable voltage. The correct transformer, sized to meet the customer's usage, is key to providing a reliable service experience.

Number of Transformers in Service Territory

There are roughly 600,000 padmount and pole mount transformers units active.

Lifecycle Analysis

The overall average lifespan of a distribution transformer as quoted by transformer manufacturers is approximately 25 years.

However, a typical transformer can exceed the manufacturer's lifespan, depending on different factors. The load and environment have the largest contribution on the health of a transformer and it's common to see transformers exceed 30 or 40 years of life.

The average transformer in the Company's service territory is 47 years old.

Supply Chain Risk

Across the industry, utilities including the Company face risk related to transformer availability.

The strain on raw materials, which began in 2020 because of the COVID pandemic, put a major constraint on transformer production in the United States. Resource scarcity also drove up the cost of transformers. However, the Company has been able to manage this supply chain risk through three strategies:

1. Using longer-term purchase contracts with vendors instead of spot purchases
2. Using a broader pool of vendors (see more below)
3. Planning further ahead for anticipated and forecast demand

High Load Risk

Transformers will be directly impacted by increased electrification of consumer appliances and transit.

The Company is anticipating the need to upgrade transformers more frequently due to the increasing loads with EV chargers, heat pumps, and other home electrification efforts.

In short, as customers begin using more electricity, the Company will have to replace more transformers more frequently to provide service for the new customer load.

Load Growth Risk

Transformers also face risk when customers drastically increase their load without notifying the Company.

Residential transformers are sized to meet traditional residential demand load. However, when customers add load after a transformer is installed without notifying the Company, this can put a major strain on the transformer and other customers whom that transformer serves.

New activities, like indoor growing operations installed in a residential home, create voltage problems for customers as well as overloads on transformers, which can lead to an earlier than expected end of life for the transformer up to and including failure.

The Company is working to diversify its supply chain and enhanced the standards of new transformers to meet the increased customer load of the future. This will help ensure we have enough transformers on hand to support our existing customers as well as meeting any new requests for electric service.

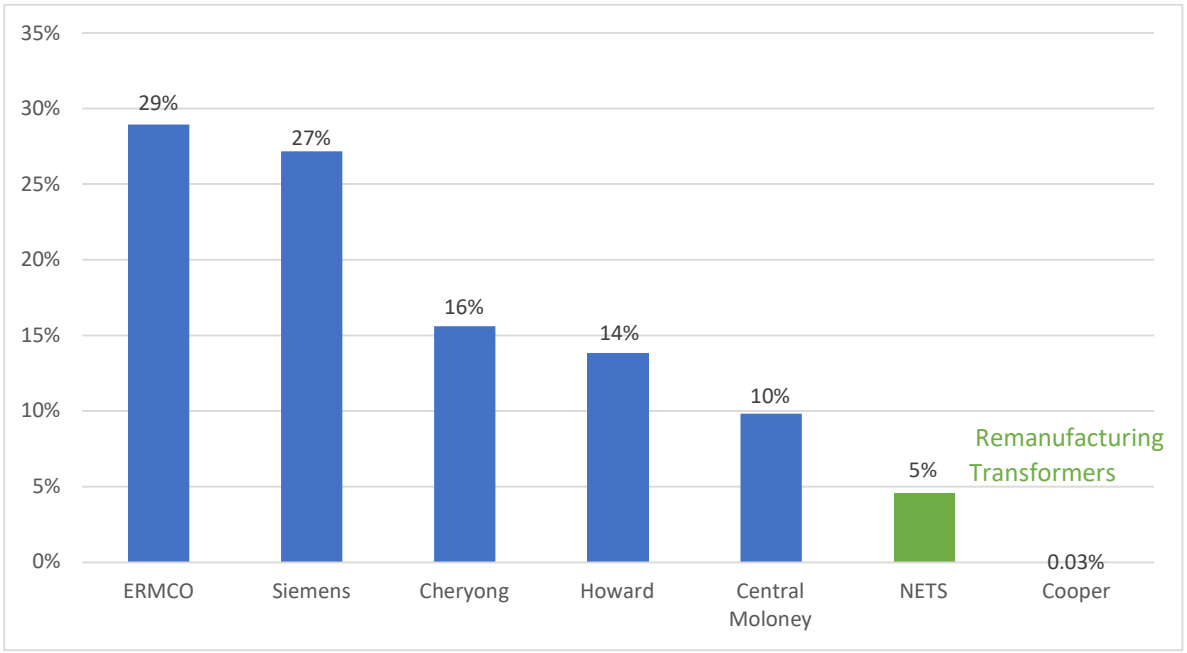
- In addition to exploring new contracts with additional suppliers, shown in Figure 67 below, the Company is also reviewing different styles of transformers that are compatible with its grid, such as *amorphous core* style units and dry type transformers.

  NOTE: Amorphous core transformers differ from traditional silicon steel transformer cores in that amorphous cores are made up of ribbons of metal that are *not* grain-oriented versus a rolled sheet of grain-oriented steel that is used in a traditional silicon steel core. **This difference in construction results in lower voltage losses in the voltage transformation process.**

The Company is also updating its standards to account for the anticipated addition of EV chargers on new builds and remodels. Taken together, these strategies will ensure the Company is able to prepare for the future while continuing to provide reliable service.

Figure 67

PERCENTAGE OF TRANSFORMERS ORDERED FOR 2025 BY SUPPLIER



The Company will procure enough transformers to serve new load requests and restore power in the event of unplanned outages on the system.

These estimates account for the drastic increase in transformer costs we have realized in 2023 as well as additional need for transformers to be available for EV adoption over the next 5 years.

The 5-year Investment Plan for LVD Transformers

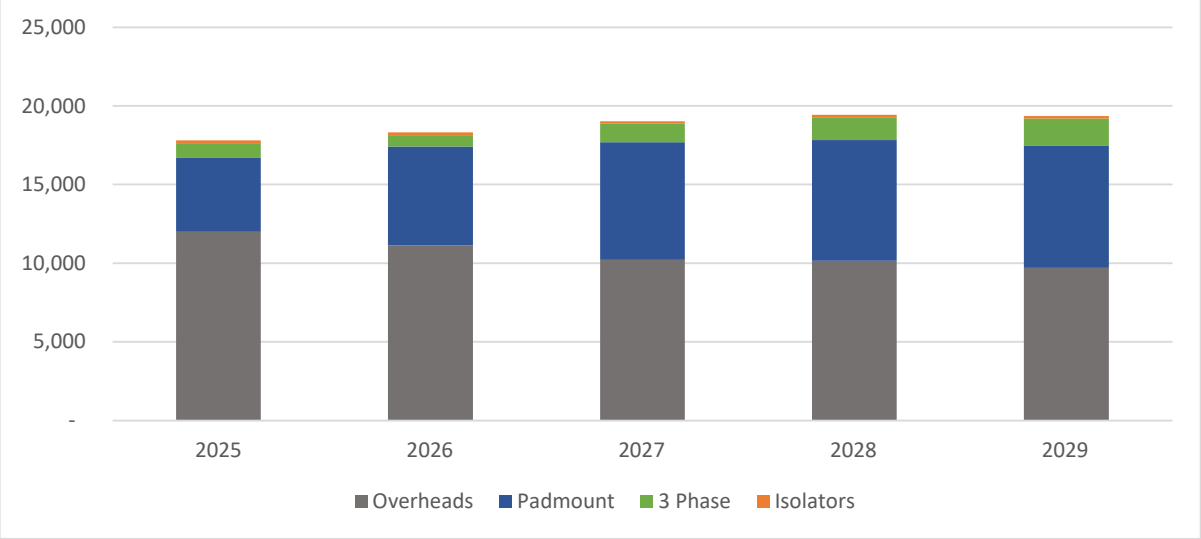
As a result of delays stemming from the COVID-19 pandemic, the Company received increased deliveries of overhead transformers in 2023 and 2024 to restock inventories of those units.

In 2025, we expect purchase volumes to return to pre-pandemic levels with some additional demand factored in. From then on, we expect that purchases of overhead transformers will remain generally level.

The Company expects a significant increase in purchases of padmount transformers tied to increased undergrounding work and the need to support customers adopting electric vehicles. This is reflected in the 5-year investment plan and unit forecast in Figure 68 below.

Figure 68

PLANNED TRANSFORMERS TO BE PURCHASED



TYPE	*2025*	*2026*	*2027*	*2028*	*2029*
3-PHASE	*927*	*741*	*1,189*	*1,464*	*1,758*
PADMOUNT	*4,690*	*6,267*	*7,469*	*7,658*	*7,746*
OVERHEADS	*12,000*	*11,135*	*10,207*	*10,157*	*9,696*
ISOLATORS	*183*	*163*	*154*	*154*	*147*

Meters

What Meters Do

Electric meters, meter sockets, and metering transformers are needed to **provide safe and reliable measurement of electricity usage** for customers.

LVD Metering investments support the Company's obligation to serve, and provide the means to measure customer electricity usage, provide the data required to generate customer bills, and provide usage data to customers safely and accurately.

Furthermore, smart meters provide customers with data to enable them to take greater control of their energy consumption.

Metering is an essential part of connecting new customers through its overall New Business Program, as well as replacing failed equipment. Additionally, *advanced metering* is an essential component in many of the Company's current and future demand response and renewable programs.

- *Advanced Metering* is defined as *an integrated system of smart meters, data management systems, and communication networks that enable two-way communication between the utilities and the customers.*

Number of Meters in Service Territory

There are roughly 1.92 million electric meters currently installed, of which 1.90 million are smart meters. The remainder are a combination of legacy (non-communicating) meters, and commercial or industrial meters.

Lifecycle Analysis

The overall average lifespan of an electric meter is 20 years. However, with the deployment of cellular smart meters, meter lifespan can be affected by the availability of the communications network, as meters contain communications modules that are network-specific, such as 3G LTE, 4G LTE and 4G CATM1.

3G Meters

From 2021-2023 the Company worked to exchange and upgrade 620,000 3G meters to 4G CatM1 technology, which is 5G forward compatible.

The goal of this project was to have all 3G meters off the system when Verizon retired its 3G LTE network. Beginning in 2023, Verizon retired the 3G LTE network making the remaining 188,000 3G meters obsolete. The Company has since completed the remaining exchanges. As of November 2, 2024, there are only 15 3G meters remaining, only 1 of which has a customer attached.

4G Long-Term Evolution ("LTE") and 4G CatM1 Meters

As of June 2023, there are 1.18 million 4G LTE meters installed on the Company system, and 700,000 4G CatM1 meters.

The Company's 4G LTE communications network provider, Verizon, has not provided a definitive date for the retirement of the 4G LTE network, but they expect to maintain the network into the mid- to late-2030s.

With that in mind, the Company is evaluating its existing metering technology, vendors, and software, including technology to support future electric and gas system integrations (e.g., Distributed Energy Management Systems ("DERMS") and edge-DERMS, among other systems).

By year-end 2025, the Company expects to have defined a strategy for eventually replacing 4G meters that accounts for Verizon's timeline.

The Company's strategy will be heavily informed by the overall investment required. Once a strategy is set, the Company will maintain the existing technology and the existing population of 4G LTE and 4G CatM1 meters for the next three to four years before transitioning to 5G meters.

The Company is also considering advanced metering infrastructure ("AMI") software that can be integrated with other grid operations software, including DERMS and edge-DERMS.

The choice between AMI technologies will not impact AMI purchasing decisions in 2025, but the choices the Company is evaluating may impact the Company's future meter purchases. Until a software decision is made, the Company cannot say what type of meter it may decide to purchase in the future.

In the meantime, the Company is currently purchasing 4G CatM1 meters, which are 5G forward compatible and therefore would not need to be replaced to use the 5G network.

With the current AMI technology in use, gas meter reads for combination gas-electric customers are transmitted to the collection system via the electric meter. Due to this interdependency, the Company must look at any future updates or changes to the AMI system holistically.

The Company identified scenarios in 2023, and in 2024 it began analyzing each scenario. The scenarios include maintaining existing technology (status quo), using a single meter vendor, and using multiple meter vendors. To test the scenarios, the Company is performing a SWOT (Strength, Weakness, Opportunity, Threat) analysis, evaluating each scenario's advantages and disadvantages.

The Company is also looking at similar functionality in use today, including automated reading, remote turn-on and turn-off, and other new functionalities being offered such as grid-edge computing.

The Company's business case for future AMI technology, when developed, will prioritize replacing technology that is obsolete.

Metro System

What the Metro System Does

The Company's Metro system provides underground electric distribution service in the downtown areas of Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw.

Metro distribution assets consist of conductors contained in duct banks encased in concrete, with transformers and switching points placed below ground in larger working spaces called vaults and smaller working spaces called manholes.

Some of the cables are made of oil-and-paper-insulated, lead-sheathed conductor that is no longer manufactured.

The Metro system also includes padmounted switchgear, which consists of above ground switches and fuses in steel enclosures and padmounted transformers.

The Metro system promotes safety by ensuring the public does not encounter energized equipment. It also promotes aesthetics, and ensures it is less disruptive to the community and businesses to conduct repairs.

Number of Assets in Service Territory

As of 2024, Metro infrastructure includes 156 total vaults and 1,429 total manholes. Vaults and manholes are connected to each other through duct banks.

Lifecycle Analysis

The expected lifecycle of Metro assets is between 45 and 62 years, with civil assets lasting longer than electrical.

Much of the Company's Metro infrastructure was first installed from 1910 through the 1950s, and is still in service today.

The average lifecycles for Metro assets along with the average ages of these assets that were retired between 2017 and 2021, are shown in Figure 69 below.

Note that many assets are beyond their expected useful life, with some assets functioning for more than double the expected life.

FIGURE 69
METRO LIFECYCLE DATA

Device	Metro Conduit/Civil Infrastructure	Metro Conductor and Electrical Assets	Metro Transformers	Metro Services
Expected lifecycle	60 years	62 years	47 years	45 years
Average retirement age, 2017-2021	88 years	61 years	N/A	46 years
Maximum retirement age, 2017-2021	121 years	101 years	N/A	69 years

Public and Employee Safety Risks

Vaults and Metro system represent a minor public safety risk due to assets being located underground in public rights of way (typically under the sidewalk), making accidental public contact exceedingly rare.

Metro System Asset Health and Risks

The Metro system consists of two primary components:

- Civil infrastructure consisting of vaults, manholes, and duct banks.
- Electrical infrastructure consisting of conductor, transformers, and controlling devices.

Each infrastructure type has unique risks detailed below.

Civil Infrastructure Risks: The biggest risk to civil infrastructure is the age and physical size of vaults, manholes, and duct banks. Today's modern electrical cables, controlling devices and transformers require more physical space to safely maintain and operate this electrical equipment.

Electrical Infrastructure Risks: The biggest risk to the electrical infrastructure in the Metro system is driven by the live primary exposed parts in vaults and padmount switchgear, which presents a safety risk to the Company's workforce. Due to the enclosed space of the vaults, employees must take precautions to maintain working space clearances when working around these live metal parts.

Lead Risk: Another risk to the electrical infrastructure in the Metro system is driven using Paper Insulated, Lead Covered ("PILC") and Varnished Cambric, Lead Covered ("VCLC") primary cables. As noted above, this type of cable is obsolete and no longer manufactured; the existing lead conductor in the Metro system is more than 50 years old. Because of this obsolescence, if lead cable fails it cannot be replaced, and instead must be spliced back together, which is a laborious process. As of 2024 the Company has more than 240,000 feet, or approximately 11% of the overall Metro system, of primary lead-covered cables of various sizes in service interconnecting the vault system to the metro substations.

Modeling & Prioritizing Risk

Metro planning and design engineers use a model to assess multiple components of each vault which produce a vault health score ranging from 0 to 180.

These components are assessed first to determine whether the risk is present, then given a multiplier based on the severity of the risk.

- Vaults with some risks present will receive a weighted score with the highest weighting given to wall, roof, and entrance condition as well as electrical connections.
- Based on the severity, a vault will be labeled as Yellow or Red, which will then multiply the score by 1 or 2, respectively.
- Vaults with no risk for a certain component are assessed as Green with a multiplier of 0.

Figure 70 below shows how the evaluation criteria is applied to a hypothetical vault.

FIGURE 70

METRO RISK ASSESSMENT MODEL

		Weighting:	10	10	10	2	4	3	1	10	7	2	5	5	4	3	4	3	3	2	2	180
			Civil							Electrical												
Asset Name	Reviewer	Review Date	Roof condition	Wall condition	Entrance condition	Entrance Location	Ventilation	Cable Rack Condition	Depth of water, as found	Electrical Connections live/dead	Working space	Switch type	Switch Condition	Transformer condition	Equipment sized for Fault Current	Grounding/Bonding Conditions	Lead cable	Splice Condition	Fireproofing/Arc Tape	Primary configuration (delta or grounded)	Alternate primary feed	Total Score
Sample Vault			R	R	R	G	G	Y	G	R	Y	Y	Y	Y	Y	Y	Y	G	R	G	G	119

Based on an assessment of these characteristics, a vault with a score above 70 qualifies for a red rating, which indicates major deterioration. A score between 51 and 70 is given an orange rating, showing moderate deterioration.

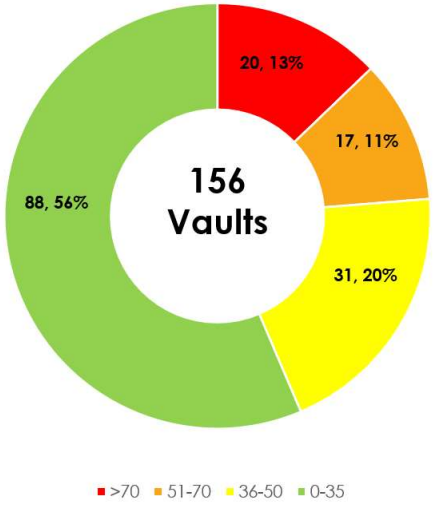
As of 2024, the most recent Company assessment of its vault health is shown in Figure 71.

This indicates that 24% of the vaults inspected show major or moderate deterioration, which the Company will prioritize.

In 2023, 27% of vaults had major or moderate deterioration; this drop is attributed to the reliability work executed over the past year. It is also important to note a drop in high-risk 'red' vaults from 28 vaults in 2023 to 20 today.

FIGURE 71

SUMMARY OF METRO HEALTH VAULT ASSESSMENT RESULTS



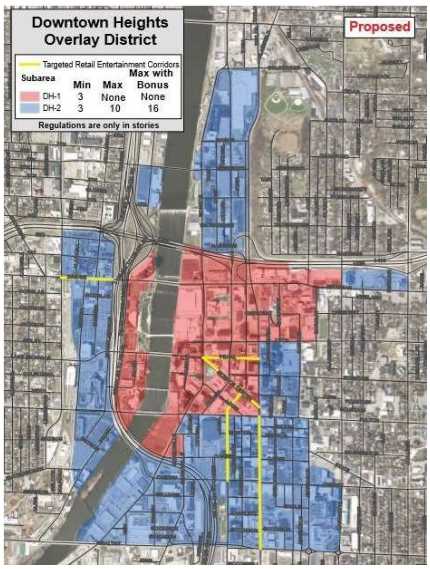
Metro System Growth & Expansion

In addition to the asset health risks on the existing Metro System, the Company is responding to major transformative plans publicly shared by municipalities that will spur economic growth, address housing shortages, and enhance urban vitality.

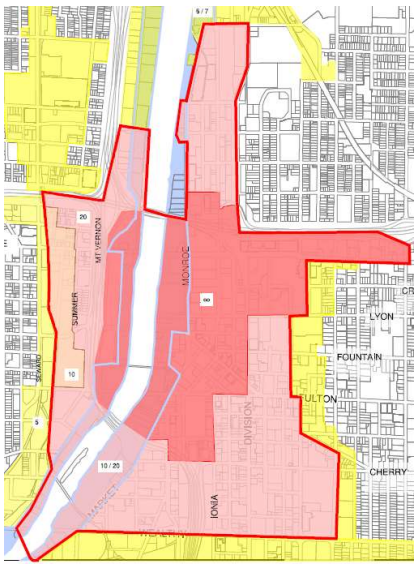
Grand Rapids is the leader in this effort. In 2023, the city approved zoning changes to allow for taller buildings in the downtown area, and expanded this area outside to the west, south and north of the traditional downtown area. These zoning changes built on earlier ones from 2017.

Figure 72

Grand Rapids Zoning Changes



2017 Height Overlay



2023 Height Overlay

In these maps, the red areas allow for unlimited building heights. In the 2017 map, the blue areas had a 10-story limit on building height. In the 2023 map, the pink areas now have a maximum building height of 20 stories.

Since the approval of the new height overlay district in Grand Rapids, developers have approached the Company with plans for new civic assets, including the planned Acrisure Amphitheater and Amway Soccer Stadium.

Each civic asset project includes additional housing development projects to address housing needs in Grand Rapids. The Acrisure Amphitheater and Amway Soccer Stadium site developers have proposed a 21-story mixed use building with 475 residential apartments near the amphitheater and a 18-story mixed use building to include 260 residential apartments.

These proposals include a Transformational Brownfield Plan approved by the Michigan Strategic Fund.

Additionally, Fulmar Property Holdings has proposed a major project with three high rise towers, including:

- 21-story, 420,000 sq ft office tower
- 43-story, 595-unit apartment tower
- 27-story, mixed use hotel and condominium tower

FIGURE 73

ILLUSTRATION OF NEW DOWNTOWN GRAND RAPIDS DEVELOPMENT



Similar developments are taking place in Kalamazoo, including a $300 million event center, along with other civic improvements including flood control and relocation of Arcadia Creek, and conversion of the city's one-way streets to two-way multimodal traffic flows. Existing Metro infrastructure under these one-way streets (Michigan Avenue and Kalamazoo Avenue) is at end of life.

The Company is taking the opportunity to rebuild the system as a 'coordination of utilities' project in 2026 and beyond.

FIGURE 74

ILLUSTRATION OF KALAMAZOO EVENT CENTER DEVELOPMENT



Additionally, the City of Saginaw, Saginaw Future, and other stakeholders have announced development of the Saginaw Medical Diamond Project, bringing medical education facilities, mixed-use commercial property, residential property, and a new waterfront park on the south side of Downtown Saginaw. The Company has committed to doing a coordination of utilities project with this development, converting existing overhead systems into a new Metro infrastructure.

FIGURE 75

ILLUSTRATION OF SAGINAW MEDICAL DIAMOND PROJECT



Investments to Address Metro Asset Health & Expansion

The Company's ideal end state would be to rehabilitate and deadfront all the vaults with moderate or major deterioration.

- The Company's strategy for civil infrastructure is to rehabilitate or rebuild at-risk vaults, manholes, and duct banks in a way that, whenever possible, aligns with projects undertaken by municipal governments, commonly referred to as 'One Dig' or 'coordination of utilities' projects.
- The preference for coordination with local authorities means that the Company cannot unilaterally decide to rehabilitate all 'red' or 'orange' vaults over a defined near-term period.

In some instances, the Company may still need to act unilaterally to execute Metro projects. Examples of this kind of situation happened recently in Jackson, where the Company rebuilt its civil infrastructure in Cortland Street between Martin Luther King Street and Mechanic Street. The Company was able to consolidate to existing vaults into one new structure. This work was done solely by the Company without coordination of other utilities or the municipality.

To ensure optimal performance and operation of the Metro system, the Company carries out the following actions to properly protect and maintain its assets:

Deadfronting and Vault Rehabilitation

The Company performs Metro vault rehabilitations and reliability deadfront projects to remediate risks to identified vaults.

The *Deadfronting* process is used to reduce employee exposure to live equipment and *involves replacing exposed primary termination points and bushings with covered or insulated components to reduce the risk of workers contacting energized components*.

Rehabilitation projects will typically replace the vault structure and its electrical components in its entirety.

The pictures in Figure 76 show the difference between exposed and deadfronted components on rehabilitation project, with a new vault installed to replace the existing structure.

FIGURE 76

VAULT BEFORE AND AFTER REHABILITATION PROJECT



The pictures in Figure 77 show a vault reliability project that rebuilt the electrical infrastructure and performed minor concrete repairs.

FIGURE 77

VAULT BEFORE AND AFTER RELIABILITY PROJECT



Replace Obsolete Electrical Assets

To remediate risks posed by obsolete lead cable, the Company has an initiative to modernize primary cables, allowing them to be more modular so additional cable can be added later if needed.

- Modernizing primary cable also improves capacity and resiliency and creates more capability to accommodate grid modernization components.
- Replacing PILC cable reduces environmental impacts during operations such as dewatering manholes or vaults and reduces occupational hazards when working on lead cable joints and splices.
- PILC cables are no longer manufactured, with replacement cable, joints, and splice materials becoming scarcer.

Metro Inspection and System Maintenance

The Company is reducing reliability and safety risks through its metro inspection and maintenance programs based on recommendations by the *IEEE, NFPA (70B)* and industry best practices.

The Company is proposing the following schedule, shown below in Figure 78, based on good engineering practice to help identify and correct problems before they result in outages.

FIGURE 78

METRO INSPECTION AND MAINTENANCE SCHEDULE

Inspection Task	Cadence	Components Checklist	Annual Cost
Vault Inspections	4 Years	Visual Inspection of vault structure, transformers, switches, cables and other components	$ 650k
Manhole Inspections	4 Years	Visual Inspection of manhole structure, cables, splices, and other components	$ 1,100k
'Hi Rise' Vault Inspections	Annually	Visual Inspection of the room/structure, transformers, switches, cables, and other components	$ 125k
Infrared Thermography Inspections	As Needed	Inspection of electrical components. Can be performed with visual inspections	$ 125k
Total	**$ 2,000k**		

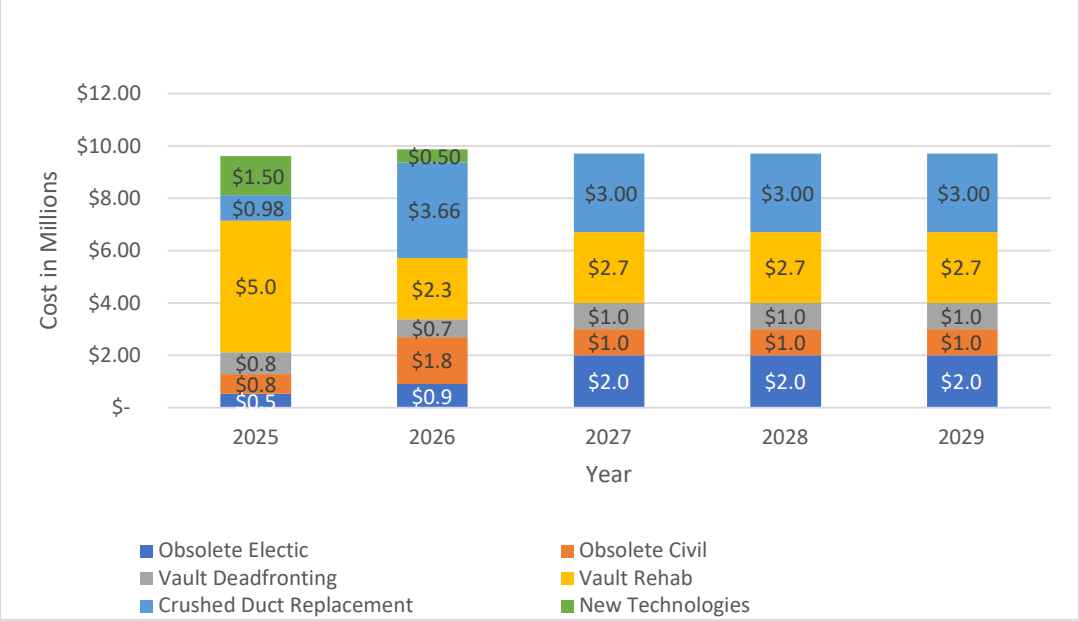
5-Year Capital Investment Plan

The Company will invest in its vaults and primary cable replacement in coordination with local governments to limit interruption of business and commerce in the municipality.

- This plan will enable the Company to complete approximately four vault rehabs, deadfront two vaults, and replace obsolete electric and civils assets on 4 or more vaults per year.
- The 5-year investment plan for the Metro system (shown below) will address workforce safety, reliability, and operational constraints.

Figure 79

METRO RELIABILITY CAPITAL INVESTMENT PLAN



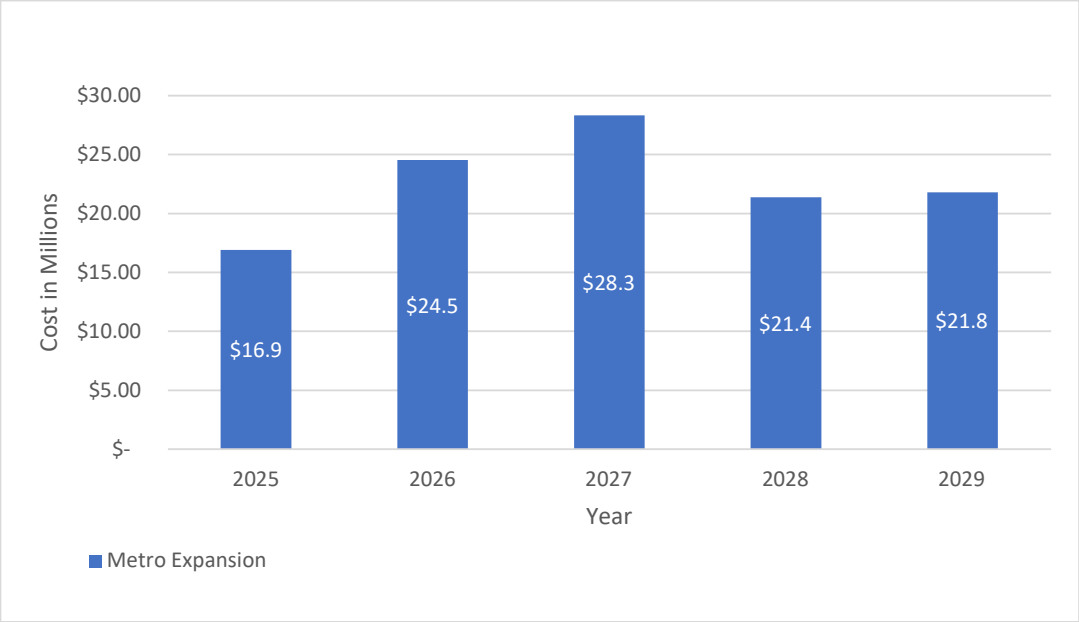
Year	Electric Projects	Civil Projects	Vault Deadfronting	Vault Rehabilitation	Crushed Duct Replacement
2025	1	1	2	6	1
2026	3	2	2	3	1
2027	4	2	2	4	1
2028	3	1	2	4	1
2029	3	1	2	4	1

The Company will invest in new business by expanding its system as appropriate.

The Company will also increase its relocation program to do 'coordination of utilities' with our municipal and internal partners.

Figure 80

METRO EXPANSION CAPITAL INVESTMENT PLAN



Year	New Business Primary Service	New Business Secondary Service	External Coordination of Utilities	Internal Coordination of Utilities
2025	10	20	25	5
2026	8	20	25	10
2027	5	15	20	10
2028	5	15	10	5
2029	5	15	10	5

Forestry Line Clearing Program

Trees are one of the greatest causes of interruptions to electric service to customers on the LVD system, contributing 43.4% of all-weather outages and 37.9% of all non-MED outages[10].

The Forestry *Line Clearing Program* manages vegetation (trees, bushes, vines, etc.) along its primary voltage systems and its secondary voltage systems, including service conductors.

[10] Percent of customers interrupted by unplanned outages in 2024 with cause code of Trees or Trees - Outside ROW.

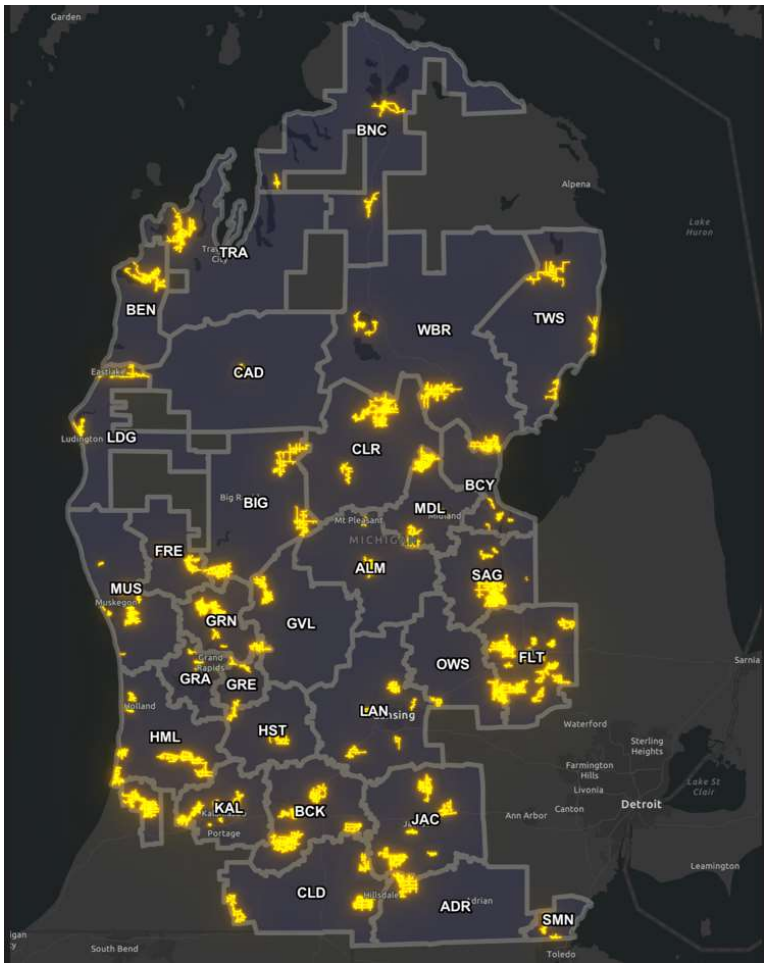
Overview of the Line Clearing Program

The Company clears vegetation within a 30-foot-wide right-of-way ("ROW") for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing. This is to maintain accessibility along the ROW for maintenance and repair of the line.

- The largest subprogram within the *Line Clearing Program* targets **full circuit clearing,** where advanced analytics identify work locations throughout the service territory on a full-circuit level.
- This portion of work, encompassing several thousand miles of LVD primary wires, is shown in the 2024 workplan snapshot in Figure 81 below, in which the geographic locations of circuits to be cleared are highlighted in yellow.

Figure 81

2024 LVD FULL CIRCUIT CLEARING WORKPLAN



The Company's *Line Clearing Program* also provides benefits that are not easily quantified, such as **improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contacts with conductors.**

The Company has been continuously maintaining a four-year clearing cycle for its HVD system. For its LVD system, the Company has been working for several years towards attaining a seven-year effective clearing cycle, but has not yet attained this cycle.

The seven-year effective cycle describes a strategy of clearing one-seventh of the LVD system miles per year with different targeted cycle lengths of clearing for the three major primary voltages on the LVD system.

Upon achieving the seven-year effective cycle:

- 14.4/24.9 kV circuits would be cleared on average between four to six years;
- 7.2/12.47 kV circuits would be cleared on average between six to eight years; and
- 4.8/8.32 kV circuits would be cleared on average between eight to ten years.

Clearing timeframe in these ranges would be dependent on the circuits' historical performance, reliability predictions, and safety considerations.

Vision for the Line Clearing Program

The Company is proposing to maintain a four-year clearing cycle for its HVD system.

For its LVD system, the Company is proposing a ramp-up to a five-year clearing cycle, while performing more aggressive line clearing on targeted three phase primary lines.

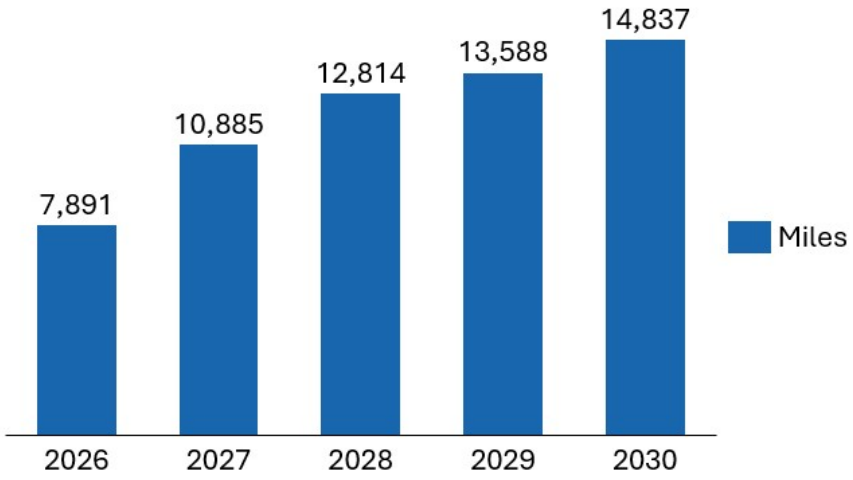
The five-year cycle strategy will involve clearing one-fifth of the Company's LVD line miles annually in steady-state cycle maintenance, while maintaining the standard that all LVD circuits have been fully cleared within a five-year period.

The Company finds that this strategy aligns with other utilities, and it has carefully evaluated the projected costs and benefits of a shorter line clearing cycle for its LVD circuits. It has determined that a five-year line clearing cycle is the right approach to significantly improve electric reliability while responsibly managing customer bill impacts.

The number of LVD miles to be cleared annually over the ramp-up period to achieve the Company's vision are displayed in Figure 82 below.

Figure 82

LVD FULL CIRCUIT CLEARING MILES



In addition, the Company will conduct more aggressive line clearing on targeted three phase primary lines through the practice of canopy removal, which is the removal of all branches above primary wires. This practice is in addition to current line clearing specifications.

- The Company's specification for LVD primary has allowed some canopy to remain (i.e., healthy, non-weak-wooded tree species canopy is cleared to 10-15' from the conductors, and certain weak-wooded tree species canopy clearance is increased to 20' from the conductors).
- The Company performed a small canopy removal study on approximately 42 miles of three phase primary in 2022.

Figures 83 and 84 show examples of canopy removal on an urban and rural section of circuit respectively, pre- and post-clearing in 2022.

Figure 83

CANOPY REMOVAL ON AN URBAN SECTION OF CIRCUIT, 2022



Figure 84

CANOPY REMOVAL ON A RURAL SECTION OF CIRCUIT, 2022



The Company is proposing canopy removal on 10%, or roughly 5,500 miles, of overhead primary, targeting three phase portions of circuits. This includes targeting three phase lines that:

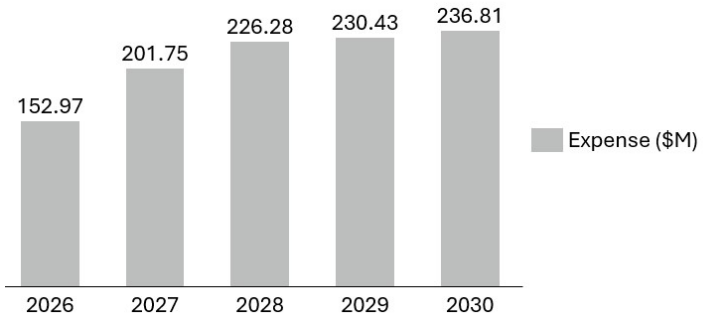
- Have the highest consequence of failure due to serving the most downstream and/or critical customers.
- Enable manual and automatic switching capabilities, reducing the impact of outages that may occur regardless of cause.
- Will inherently include first zones, some second zones, and may extend past the second zone depending on the zone attributes, like customers served downstream, and/or if the conductor is within the path of substation-to-substation connection to enable switching opportunities.

Enhancing the Company's Line Clearing Program by reducing the cycle will improve reliability and public safety. Reducing the amount of time that passes between clearings results in a smaller amount of growth, and therefore less biomass removed at the time of clearing. This results in a predictable result for customers on what their trees will look like after line clearing.

The projected LVD expenses over the ramp-up period to achieve the Company's vision are displayed in Figure 85 below.

Figure 85

LVD VISION PROJECTED EXPENSES



Reliability Benefits of the Line Clearing Program

- The Company's vision will result in clearing an increased number of miles each year to attain the reduced cycle. Line clearing reduces the risk of tree-conductor interference, which can cause customer outages. The prevention of outage incidents results in a better customer experience through reduced tree-caused SAIDI and SAIFI. For circuits cleared entirely in 2022, tree-caused primary outages including MED decreased 60% the year following clearing.
- For circuits cleared entirely in 2022, tree-caused primary outages excluding MED decreased 63% the year following clearing.

Previous analysis indicated, following completion of line clearing, the average LVD circuit reliability improves by:

- Approximately 300 fewer customers experiencing more than 3 outages in the year after tree clearing.
- Approximately 125 fewer customers experiencing outages lasting longer than 24 hours in the year after tree clearing.
- Approximately 225 fewer customer outages during catastrophic storm events within the year after tree clearing.

Figure 86 shows the projected tree-caused primary outage incidents including MED over the ramp-up period to achieve the Company's vision.

Figure 86

2026-2030 PROJECTED TREE-CAUSED PRIMARY OUTAGE INCIDENTS INCLUDING MEDS

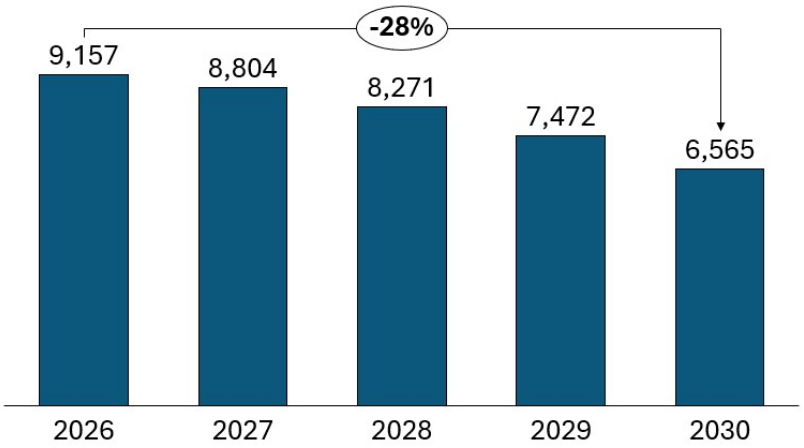
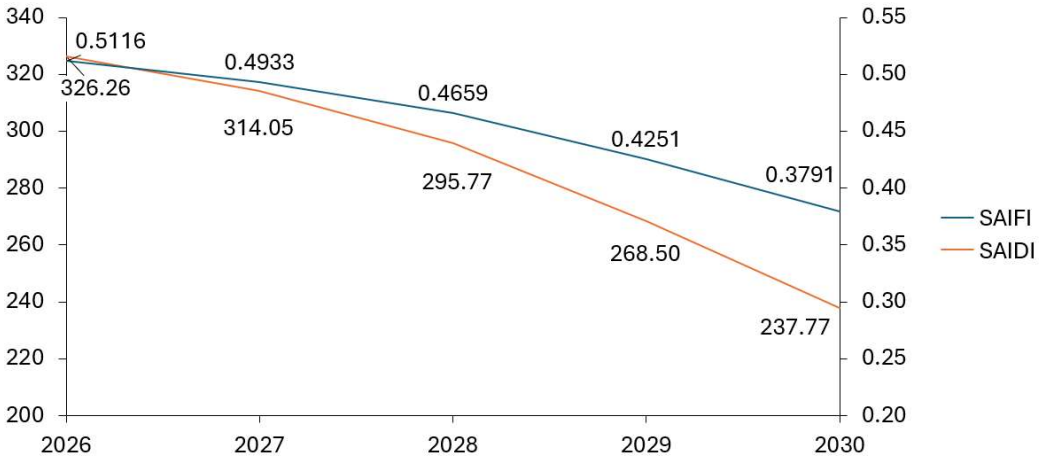


Figure 87 shows the tree-caused outage contribution to SAIFI and SAIDI over the ramp-up period to achieve the Company's vision, driven by a 28% projected primary outage incident reduction from 2026 through 2030.

Figure 87

2026-2030 PROJECTED TREE-CAUSED PRIMARY SAIFI AND SAIDI INCLUDING MED



Forestry Technology Enhancements

The Company continues to perform an in-house review of the line clearing process with the Company's Operations Performance group and Transformation departments to determine what opportunities exist to improve data analytics and performance.

- The Company recently identified an opportunity to modernize its forestry model by harnessing more sophisticated predictive and prescriptive analytics in Machine Learning and satellite imagery analysis to influence and guide its LVD full circuit clearing subprogram.
- This model is built into a web-based tool, called Forestry *Workplan Intelligence & Strategy Engine* ("WISE"), to allow for a consistent, stable, and sustainable methodology to optimize the yearly LVD full circuit clearing workplan, and to capture the most reliability and safety benefit for annual spend.
- Among the most impactful advancements in model maturity are integrating new data such as historical weather data, detailed circuit attributes, tree canopy cover data derived from *National Agriculture Imagery Program* ("NAIP") satellite imagery, and pole attributes.

These, coupled with increased analytic capabilities, **provide a more robust predictive outage model to inform the annual LVD full circuit clearing workplan,** thus allowing the Company to target its line clearing work where it will be the most impactful.

After careful consideration, the Company decided on an internal approach to technology-based enhancement of the work selection process through the development of the Forestry WISE tool.

An internal build of a digital product helps to ensure the tool is flexible in the event of change; for example, the tool currently analyzes and chooses work on a circuit-level, but the Company is pursuing opportunities to gain additional insights through pursuing LCP-level granularity in Forestry WISE.

This opportunity to take a more surgical approach to line clearing is especially impactful in areas of poorly performing circuit segments within an otherwise well-performing circuit. Not only does this **aid in selecting locations for line clearing,** but also provides higher-level data granularity, reliability prediction, and analytic tool integration that fuels intra-circuit strategy.

- For example, it can take several months for line clearing crews to clear trees along a large circuit, and it is in the best interest of both customers and the Company to first position crews at the worst performing sections of that circuit and prioritize those areas accordingly over the next several months of clearing.
- This strategy prevents more outages within the timeframe of clearing than otherwise clearing the circuit from one end to the other.

The Company is also capturing Light Detection and Ranging ("LiDAR") imagery to inform and support the execution strategy of LVD line clearing tactics in relatively high-risk wildfire areas. The Company is proposing to continue this annually to evaluate the benefits of utilizing this data on a small scale first, before re-evaluating expanding this to a larger scope, up to and including LVD system-wide utilization.

This supports the Company's phased approach to imagery analysis utilization: short- to medium-term utilization of zero- to low-cost satellite imagery analysis and focused LiDAR projects during the ramp-up to a five-year cycle, and long-term re-evaluation of larger scope LiDAR acquisition and utilization to further reduce outages once the LVD system is fully on the five-year cycle.

Service Restoration

The Company's Service Restoration program prepares for and executes work related to public emergencies and restoration activities for all outage categories, including MEDs[11] and Catastrophic Events[12].

This work includes addressing hazards such as broken poles, wire downs, and emergency orders. In addition to the workplan projections, this program includes the non-capital portion of standby costs and on-call costs for resources, such as travel, lodging, and food costs for storm responders.

Current Service Restoration Capabilities

In normal operations, the Company makes available approximately 140 crews and 60 electric service workers ("ESWs"); this can vary based on vacations, sick leave, and training. This enables the Company to respond effectively to approximately 40,000 customers experiencing an outage in a 24-hour period before additional resources are required.

When severe weather or a storm creates incidents beyond the Company's standard capabilities, the Company may need additional crewing and will reach out to off-system crews to supplement the Company's resources.

- Off-system crews are primarily obtained as necessary from other utilities, municipalities, and contractors, and are deployed when all Company resources are engaged.

The Company uses an Incident Command System ("ICS") to address emergency situations, and storm response is always addressed through an ICS.

Within the Company's ICS, crew-to-dispatcher ratio is maintained at no greater than 15 to 20 points of contact with field personnel. To control the number of points of contact, field leaders obtain work from dispatchers and issue work assignments to five to seven crews, allowing for a greater span of control and efficiency with field personnel.

The Company uses an outage prediction model to analyze current weather patterns, past outage history, and machine learning to determine the approximate number of customers and geographic locations that may be potentially impacted. In some cases, the Company may pre-stage resources in locations where severe storm impacts are expected, meaning those resources can be ready to respond as soon as possible after outages occur.

The Company is currently operating four separate control centers, located in three separate facilities in Jackson and Grand Rapids as shown below in Figure 88.

These centers operate 24 hours a day, 7 days a week, with the following general areas of responsibility:

- **The System Control Center**, in Jackson, controls HVD lines and HVD substations.
- **The Distribution Control Center**, in Grand Rapids, controls LVD substations.
- Two **LVD Dispatch Centers**, one each in Jackson and Grand Rapids, controls LVD overhead and underground lines.

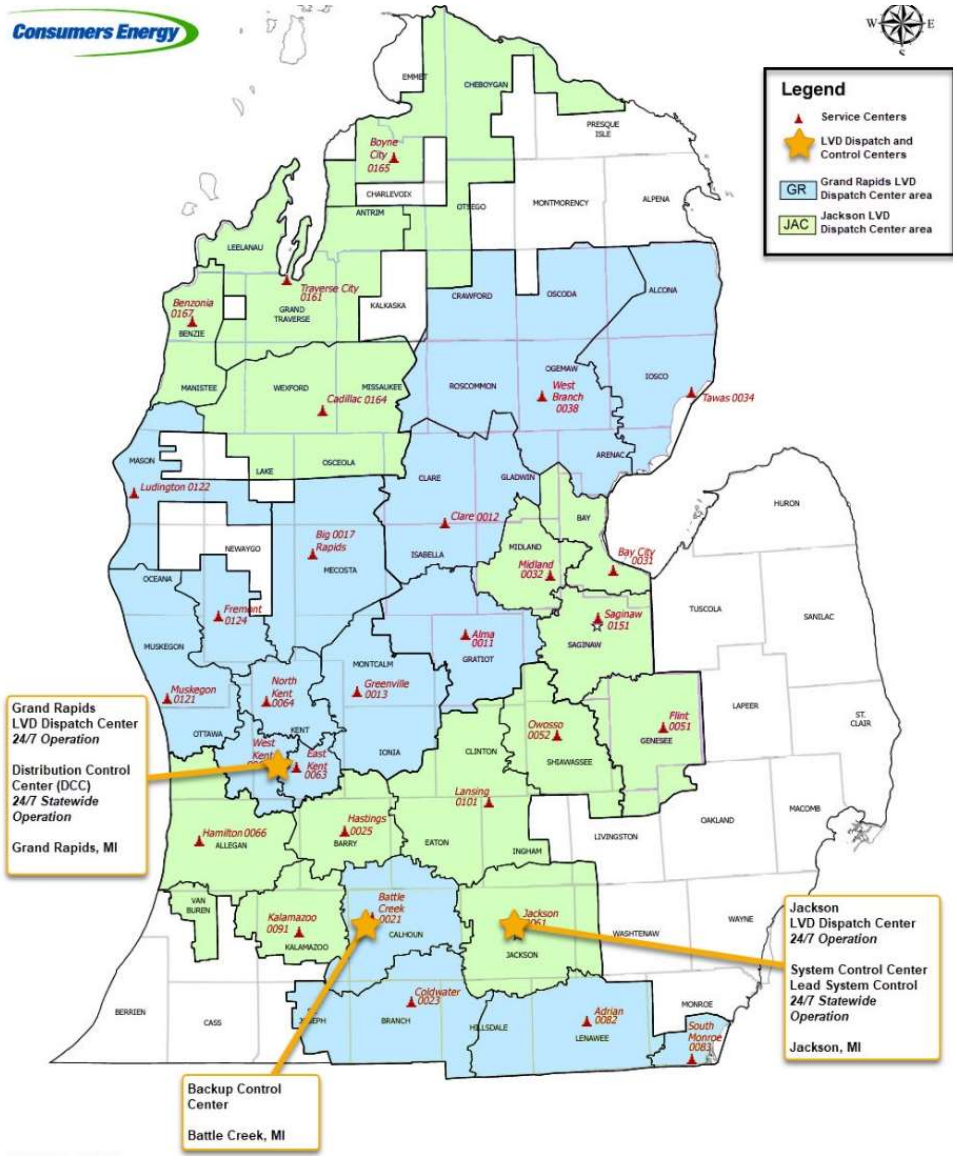
[11] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily SAIDI values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

[12] Catastrophic Events is defined in the Public Service Commission *Service Quality and Reliability Standards for Electric Distribution Systems* R 460.702(c).

Staffing in these control centers is increased as required during storm restoration. Storm support is operated from all four centers, depending on the severity and impact to the system, with statewide ICS operations managed from the Emergency Operations Center, also in Jackson.

Figure 88

SYSTEM CONTROL, DISTRIBUTION CONTROL AND LOW VOLTAGE DISTRIBUTION DISPATCH CENTERS



Gray Sky and Catastrophic Service Restoration

High impact Gray Sky storm events (greater than 1% but less than 10% of a utility's customers are out of power) and Catastrophic Storm events (greater than 10% or nearly 190,000 customers of a utility's customers are out of power) provide the greatest challenge and opportunity for the Company to improve Service Restoration performance.

The investments outlined in this plan will result in fewer outage events; the Company will realize savings from having to restore fewer outages, but those savings will be more than offset by the cost to add incremental Service Restoration resources to meet the improved restoration times required in the *Service Quality and Reliability Standards for Electric Distribution Systems* that were implemented in April 2023.

As a result, the Company's strategy is focused on controlling costs through improved productivity and waste elimination.

- To illustrate this point, in August 2023, the Company acquired a record level of Electric Line Crews to restore customers following a catastrophic storm (660 crews) but did not achieve the 90% customer restoration MPSC Performance Standard within 48 hours.
- Contrasted with the August 2023 Storm, the August 2024 Catastrophic Storm enabled the Company's fastest restoration of 150,000 customers (<42 hours), with 500 crews.

The Company was able to restore 95% of customers within 48 hours. This was tied to a deliberate approach to improve productivity and eliminate waste. Through month-end November 2024, the Company has spent $30M less O&M versus 2023; this is despite more storms (small and large) and more outages. Through waste elimination, Consumers Energy has improved field productivity by 13%.

To meet the MPSC Performance Standards and meet customer restoration expectations, the Company will need to continue to balance costs with productivity.

The Company's service restoration planning begins several days prior to an actual event. Meteorologists develop forecasts that are incorporated into an outage prediction model.

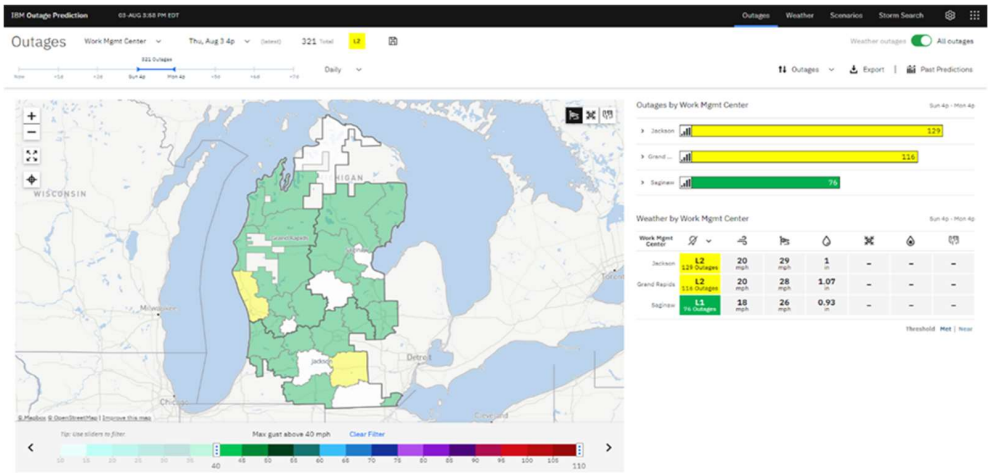
Figure 89 is a snapshot of our prediction model. The boundaries of our service centers are outlined within the State. The model is run every hour each day. Service areas with elevated outage forecasts are visibly displayed.

In the example below, our Emergency Response team used the model to ensure sufficient resource availability to respond to elevated outages in our Grand Rapids and Jackson Work Management Centers.

Written weather forecasts are received every 12 hours; 365 days a year to inform our prediction model. This ongoing planning cycle ensures we have restoration plans in place to meet or exceed acceptable levels of restoration performance.

Figure 89

OUTAGE PREDICTION MODEL



Workplan

In addition to meeting performance levels for customers set by the Commission[13], **the end goal for Service Restoration is a minimum frequency and quantity of outages,** as well as reduced response time for resources, optimal operational efficiencies between control centers, and maximum on-the-job time for field resources.

As described earlier in *Non-Load Challenges* from the Challenges from Customer Technology Adoption section, the electric grid is expected to become much more complicated with DERs coming online at the distribution level of the grid.

This increase in DERs will aid with the transition to a two-way power flow with more renewable generation; however, managing this shift in grid operations requires optimized communication with those employees who operate the electric grid.

To achieve both internal and MPSC defined goals, the Company is consolidating Distribution Control, LVD Dispatch, and System Control centers into two fully staffed Control Centers—one in Jackson and one in Grand Rapids. Each center will serve as a backup for the other, with associated process and organizational changes delivering significant customer benefits.

This consolidation is key for implementing grid operation improvements under all conditions including:

- Improving communications with the co-location of Grid Operators.
- Adopting an optimized demarcation of responsibilities among the groups managing the grid.
- Increasing the authority of field resources to manage outage incidents.
- Ensuring continuous operations during disruptions by having two fully staffed control centers that can back each other up.
- Faster and more effective response to emergencies, minimizing downtime and maintaining service reliability.
- Reduction in System Average Interruption Duration Index (SAIDI) through improved storm readiness and operational efficiency.

The cost savings will be attained by:

- Balancing storm and non-storm resources and workload to be able to run 70% of storms without activating ICS (typically storms below 50,000 customers).
- Improving processing efficiencies of outage incidents by using automation, and leveraging data provided by Line Sensors, ADMS, and other Supervisory Control and Data Acquisition (“SCADA”) devices.
- Reduction of overtime for field and office resources

The Company’s consolidation of the Distribution Control, LVD Dispatch, and System Control centers into the UCC will cost $30.7 million over four years.

[13] Unacceptable levels of performance are defined in the Public Service Commission *Service Quality and Reliability Standards for Electric Distribution Systems* PART 2.

Figure 90

UNIFIED CONTROL CENTER ANNUAL COST AND CUMULATIVE SAVINGS



In concert with UCC, investments in technology, analytics, and grid modernization are key enablers for our Restoration Management team to meet service restoration expectations.

HVD Asset Management

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations.

The HVD system is the backbone for the entire distribution system. Investments in the HVD system ensure that the foundation of the distribution system is reliable and resilient, as HVD outages impact thousands of customers and entire communities at a time. Reliability is accomplished through addressing deteriorated, obsolete, and failing assets.

This section will focus on each HVD asset in detail, with a comprehensive overview of major risks, and the workplan to mitigate risks and five-year investment category for each asset class including:

- Mitigating the risks from deteriorated switches, poles, pole tops, and conductor through **HVD Lines investments**
- Mitigating the risks from deterioration through securing, inspecting, and upgrading **HVD and LVD Substations**
- Enhancing and modernizing the protective system with **System Protection Relays**
- Ensuring the HVD System can serve electric peak demand, new interconnections and support economic development through **HVD Load Growth & Interconnections**

Trees are a significant external risk factor for HVD Lines, and the Company has an HVD line clearing program to address this concern.

As with LVD investments, each HVD asset investment plan includes the planned capital expenses to construct the distribution assets, and the O&M expenses for preventative work, compliance requirements and emergent repairs.

Adequate funding for capital as well as O&M is vital to ensuring both the reliability and cost efficiency of the distribution system through taking proactive measures to address problems before they occur. Continued funding of O&M and adherence to O&M standards provides:

- Increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation.
- Decreased costs by avoiding emergency repairs, allowing for more predictability in the workplan.
- Extension of asset life, avoiding emergent capital replacements and allowing for more predictable future capital investments.

HVD Asset Health Model

The Company evaluates the asset health of HVD lines and substation assets through annual inspections, maintenance, and diagnostic testing.

These key data points are reviewed and collected to build an asset health model, used as a tool for prioritizing investments by evaluating all assets that face declining asset health.

The asset health model considers multiple inputs like asset type, manufacturer, condition, age, actual outages, and level of degradation collected about the asset during inspections, maintenance, and/or annual diagnostic testing to provide a holistic view of the asset's health.

For each type of asset, the asset health model incorporates critical asset factors such as inspection results and testing results, plus known manufacturing issues that affect certain types of equipment. In the case of substation transformers and breakers, asset age is also one of the factors included in assessing risk, because these assets have a known correlation between age and failure.

An HVD line's asset health score combines multiple data points that include if it is a radial line or not, potential customer impact, type of conductor, configuration, number of trips, number of lockouts, red tagged poles, and victor insulators.

Figure 91 below shows the point value assigned to each factor of a line segment that helps generate its overall health score, and Figure 92 shows a sample calculation of a line segment health score.

FIGURE 91

HVD LINE ASSET HEALTH WEIGHTING

Radial line	Points per mile	5
Customers	Points per 1,000	2
Obsolete conductor	Points per mile	5
Unshielded conductor	Points per mile	1
Top 25 contingency	Yes	0
Trip	Points per trip	1
Lockout	Points per lockout	2
Rush red tagged pole	Points per pole	2
Planned red tagged pole	Points per pole	1
Victor insulators	Point per insulator	0.3

FIGURE 92

HVD SAMPLE HEALTH SCORE BY LINE SEGMENT

Line Name	Total Point	Radial	Customer Impact	Obsolete Conductor	Unshielded	Victor Insulators	Red Tagged Poles	Lockout
Line Segment A	133	30	6	0	0	60	25	12
Line Segment B	100	0	10	50	10	0	30	0
Line Segment C	86.6	25	5	0	0	3.6	45	8

An HVD substation's asset health score combines the scores of multiple components within the substation. Figure 93 below shows an example of an asset health score for a substation, showing how multiple component scores total the station score. Figure 94 shows how transformer factors impact the total score for the transformer.

FIGURE 93

HVD SAMPLE HEALTH SCORES FOR SUBSTATIONS

Category	Points per Occurance	Sub A	Sub B	Sub C
AC/FP/REC Wound	25	0	0	0
Age 50+	20	1	1	1
Oil or N2 Leaks	10	1	1	0
Transformer Internal Infrared	10	0	1	0
DGA Score	20	1	0	0
Brand A Bushing Issue	15	1	0	0
Brand B Bushing issue	5	0	0	0
IR P1/P2	20	0	1	0
Doble or Elec Test Issues	15	0	1	0
Transformer & Bushings Total		65	75	20
REG/LTC TOA R3/4	25	1		
IR P1/P2	20			
REG/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3PH Reg/LTC Demand Order	10	1		
BRKR Oil or SF6 Gas Quality/Leaker	15		1	1
IR P1/P2	15			
Maint/RP Priority List	10			
Oil and Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSWs/VSW Issues	15	1		
SPT Watch List	10	2	1	1
Str & Concrete	5	1		
Other	5			
IR P1/P2	15		1	1
Ops Limiting Equip	20	1		
Station & Other Totals		60	25	25
Total Score Normalized		100	66.66667	33.33333
Gross Total		195	130	65

FIGURE 94

TRANSFORMER ASSET HEALTH WEIGHTING

Factor	% of Total Score
Age over 50+ years	14%
How the Transformer is Wound	18%
Nitrogen Gas or Oil Leaks	7%
Allis Chalmers Infrared	7%
Dissolved Gas Analysis	14%
Bushing Type	4-14%
Electric Testing Results	11%

HVD Lines

Figure 95

EXAMPLES OF HVD LINES



What HVD Lines Do

HVD Lines carry electric power at high voltage from a source substation to several substations.

HVD Poles are comprised of a pole top, which includes cross-arms, insulators, conductors, and switches that sit atop a wooden or steel pole.

Line miles in Service Territory

The HVD system is comprised of around 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines, and 19 miles being 46 kV underground lines. Approximately 200 miles are 138 kV overhead lines, and 4 miles being 138 kV underground lines.

Lifecycle Analysis

The overall average lifecycle of an HVD line is 60 - 70 years for the physical HVD poles. The life expectancy for pole top hardware, such as cross-arms, insulators, and cross-arm braces, is 30 - 35 years or roughly half the life of poles.

Safety Risks to the Public

HVD Lines represent a minor public safety risk since the height from the ground makes public contact exceedingly rare, however, the deterioration of the Company's HVD poles shows that poles that fail can reach ground level either from deterioration, storms, or vehicle accident.

HVD Line Asset Management Health and Risks

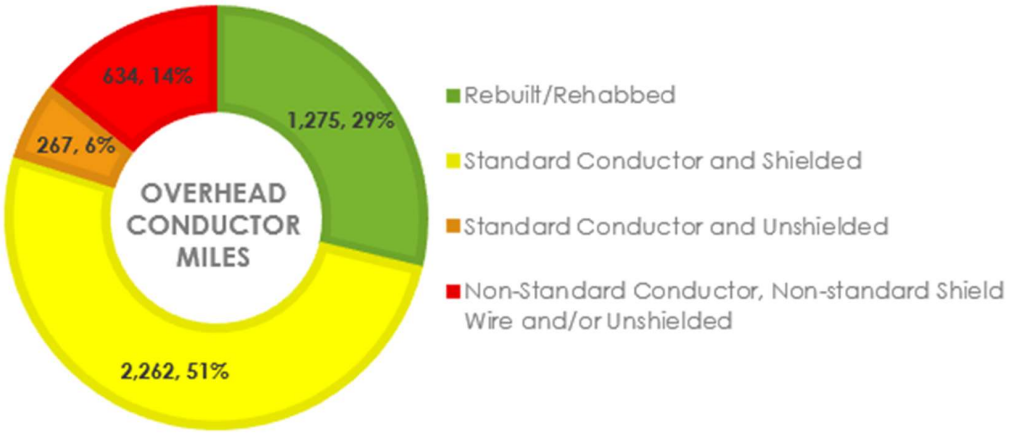
Conductors

'Non-standard conductors' made from copper or small single layer aluminum conductors with a steel core wire do not meet the Company's present design standards. This is due to the increased probability of an outage from icing conditions, weather events or tree incidents compared to multi-layer aluminum conductors.

- Previously installed copper conductors have become obsolete across the industry, making maintenance and procurement of replacement parts difficult.
- These conductors were installed between the 1930s and 1950s on 40'-55' poles that are more susceptible to tree-related outages, due to their short height compared to today's design standards. Outages that occur on non-standard lines constructed with these styles of copper or small single layer aluminum conductors are regularly of longer duration and increased cost due to complexities in working with the degraded conductor.

The most recent Company assessment of HVD conductor health shows nearly 14.4% of HVD conductors are a high priority for repair and replacement based on being non-standard conductor and/or unshielded. Another 6% are in the moderate concern category, based on being unshielded, as shown in Figure 96 below.

FIGURE 96
HVD LINES CONDUCTOR HEALTH



Insulators

Over the past five years, on average, **insulators have been the largest contributor to customer minute interruptions on HVD lines**. These failures are driven by vintage insulators, including victor type insulators.

- The Company has approximately 15,000 victor type insulators that were installed between 1969 and 1994, and their replacement is prioritized in this plan.

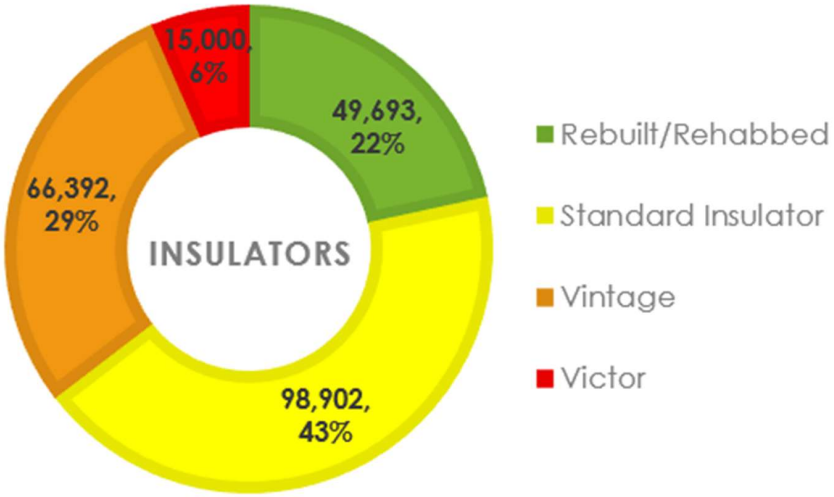
The Company has been leveraging artificial intelligence software and machine learning to automate the review of annual helicopter inspection video, which helps identify specific locations of vintage insulators, including victor type insulators.

As insulator locations are identified via machine learning, the Company can categorize the different types of insulators to enable improved planning of replacements.

The most recent Company assessment of HVD insulator health shows 6% of HVD insulators are victor type insulators and are a high priority for repair and replacement, and another 29% are in the moderate concern category as vintage insulators.

FIGURE 97

HVD LINES INSULATOR HEALTH



Poles

The Company currently maintains a 12-year cycle for HVD pole inspections.

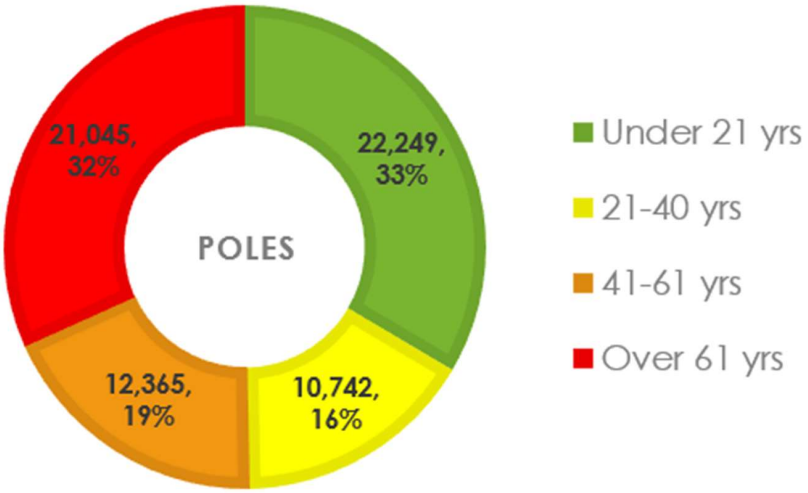
Pole inspections identify poles as candidates for replacement, regardless of pole age. Currently, the Company has a backlog of approximately 2,500 identified poles from inspections prior to 2025 that are in need of replacement, in addition to those newly identified in ongoing inspections.

The most recent Company assessment of HVD pole health shows one-third are over 60 years old, with 19% being between 40 and 60 years old, as shown in Figure 98 below.

While age is not determinative of the need for replacement, increasing HVD pole age generally indicates that to the Company will find increasing numbers of poles to replace during annual pole inspections, as more poles approach the end of their engineered lifecycle.

Historical data shows that 8-12% of HVD poles inspected each year will fail inspection and be identified for replacement. The Company incorporates this data into the overall system condition and defines a plan to replace the poles. This pole inspection is in addition to annual helicopter and ground patrol inspections of all HVD lines that are described in more detail later in this section.

FIGURE 98
HVD POLE HEALTH



Trees

Trees present a potential risk of outage or interruption of electric service on the HVD system.

The Company's *Forestry Line Clearing Program* for HVD is designed to minimize the risk of these occurrences, improve reliable service to its customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events.

The Company clears vegetation within an 80- to 120-foot-wide ROW for these voltages to attain a minimum of 15 feet of separation for 46 kV lines, and 20 feet of separation for 138 kV lines between conductors and vegetation at the time of clearing. This wider clearing standard ensures better reliability and fewer tree hazards on the HVD system.

The Company also manages vegetation within the ROW to maintain accessibility along the ROW for maintenance and repair of the line. The HVD Line Clearing Program is currently on a 4-year clearing cycle.

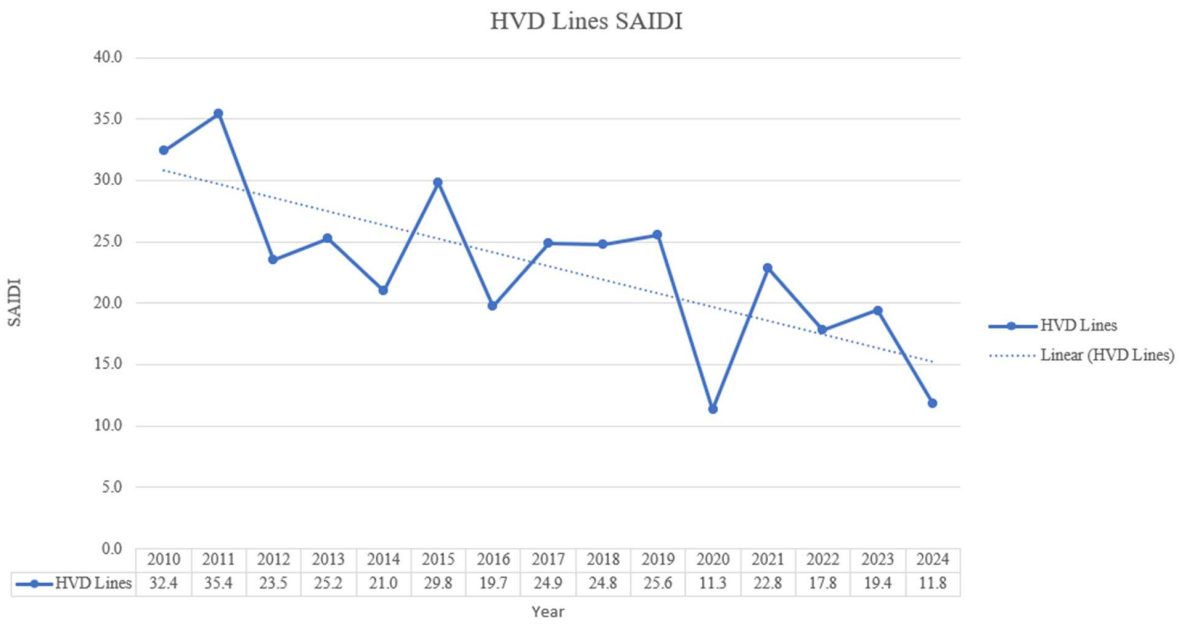
Investments to Address HVD Lines Asset Health

The Company plans to fix and fortify the HVD lines system by replacing deteriorated assets that poses a heightened risk of failure, as identified by inspections. In addition, the Company will address HVD lines identified through the asset health model as being in poor asset health, considering conductor type, configuration, outages, and insulator type.

The Company focuses on lines with consistently poor reliability performance and looks for the best remediation strategy to prevent future outages in the most effective and economical way. After addressing defects identified through inspection practices, the **primary driver for investment decisions is line performance**—lines with the highest average of incident rates and customer outage minute totals in a rolling three-year period are given higher priority for remediation.

As Figure 99 below shows, the reliability performance of the HVD system has steadily improved due to the Company's aggressive investment in HVD lines.

FIGURE 99
HVD LINES SAIDI PERFORMANCE



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
HVD Lines	32.4	35.4	23.5	25.2	21.0	29.8	19.7	24.9	24.8	25.6	11.3	22.8	17.8	19.4	11.8

The Company's HVD lines investment priorities address the system health risks of victor or vintage type insulators, non-standard conductors, and deteriorated poles, pole tops and switches identified through inspection practices.

While this has SAIDI benefits, the larger impact is the avoided outages that never occur when the Company addresses deterioration w a high likelihood of impacting thousands of customers per incident.

As can be seen in Figure 100 below, since 2022 the Company has seen a significant increase in avoided SAIDI identified through inspections, which indicates that the system is deteriorating faster than assets are replaced through planned work.

Based on regular inspection results and annual planning the Company will use the following approaches to improve the performance and longevity of all HVD lines:

Repair and Replace Deteriorated Assets

The Company monitors the health of its HVD line segments based on multiple factors including actual outage history, conductor type, shielding, line configuration looped or radial, insulator type, and the potential customer impact if the line segment were to fail. This provides a first cut for Company engineers regarding where preventative outage work would be most beneficial.

The Company also performs an annual reliability planning review of its HVD line sections, considering both line performance and line condition, to determine which lines and line components need to be addressed in the next year or years, as some projects may be large enough to span multiple years.

The Company addresses asset and line health using a combination of line rebuilds, pole top rehabilitation, switch replacements and pole replacements to reduce the population of these risks and improve reliability performance.

- With few exceptions, lines that use non-standard and obsolete construction or equipment are rebuilt to the modern standard with a new insulator, conductor, cross-arms, structure replacements, tree clearing, and ROW procurement as needed.
- Lines that use standard construction and conductor, and have adequate pole health, but have deteriorated pole top equipment and/or, vintage insulators are rehabilitated via pole top rehabilitation instead of a complete rebuild.
- Switches found to be inoperable or failing are replaced with new switches equipped with SCADA controls, allowing them to open and closed remotely to reduce customer outage time.
- The Company's overall HVD Lines workplan to rebuild or rehabilitate lines and replace poles, pole tops and switches to address the long-term asset health of the HVD Lines systems will on average will touch 4,300 structures, impacting approximately 13,000 insulators and 50 switches per year.

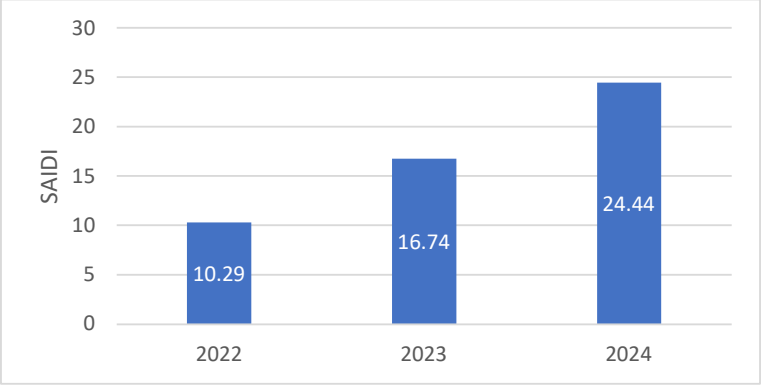
HVD Annual Line Inspections

The Company inspects HVD lines annually, addresses the anomalies found, and fixes defects before they cause a customer interruption.

- More than 4,200 miles of HVD line inspections are performed by helicopter each year, using visual observation and with infrared and ultraviolet cameras to detect anomalies and deterioration before a failure occurs.
- For safety reasons, helicopters do not fly approximately 400 miles of the HVD system. This is because it is difficult to land quickly and safely in the event of an emergency. Most of these "no-fly lines" are in densely populated urban areas. To inspect these lines, the Company completes biannual ground patrols that may include infrared and/or corona inspection using handheld cameras.
- The Company's pole inspections not only identify poles that need to be replaced in the coming year, but also poles that require immediate attention. The poles are addressed in an expedited manner to prevent outages to customers.

As the Company identifies anomalies through its inspections, it mitigates any defects identified during inspections that would fail within months and cause interruptions to customers if not addressed (anomalies are typically addressed within one to two weeks of identification). The Company then calculates the SAIDI minutes that would result if the affected asset failed and caused interruptions to customers. These avoided SAIDI minutes in historical years are shown in Figure 100 below.

Figure 100
HVD SAIDI AVOIDED THROUGH INSPECTIONS



Operations and Maintenance (O&M)

As described earlier, the Company uses aerial, ground, and pole inspections to assess the condition of the HVD Lines system.

Funding of the operations and maintenance program for these inspections provides increased reliability by identifying equipment nearing failure and making repairs before an outage can occur.

O&M funding is used to support inspections, as well as O&M related corrections to HVD lines assets like fixing hot connections, splices, broken guy wires, calibrating switches, and removing trees from lines during outages.

The Company has seen a continued reduction in HVD Lines SAIDI minutes because of an increased investment in HVD Lines asset health, with a focus on line and equipment inspections, and preventative maintenance.

Even with a downward trend in SAIDI, the *Reliability Roadmap* will require additional O&M funding to sustain this momentum. The increased O&M funding would be used to increase helicopter inspections, expand switch and pole inspections, and to repair all anomalies identified during the inspections.

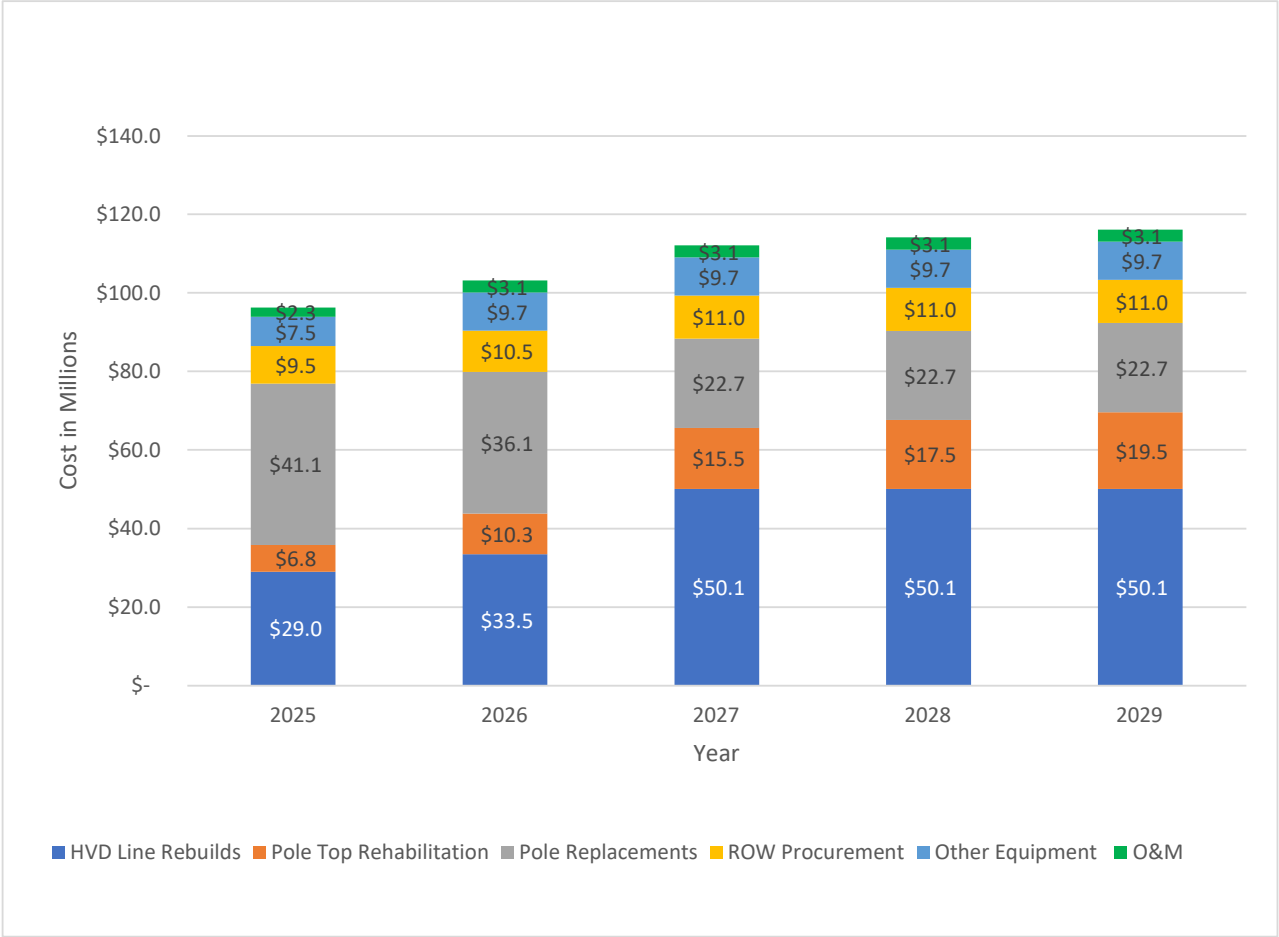
5-Year Investment Plan

The Company will rebuild or rehabilitate an average of 175 HVD line miles per year and replace approximately 1,200 poles per year as part of this plan to support the company's reliability goal.

The 5-year investment plan for HVD Lines is below.

Figure 101

HVD LINES 5-YEAR INVESTMENT PLAN



Year	HVD Line Rebuild Miles	Pole Top Rehabilitation Miles	Pole Replacements
2025	10	41	1,508
2026	47	91	1,323
2027	77	94	830
2028	77	115	830
2029	77	135	830

Substations

What Substations Do

The purpose of a substation is to receive power at one voltage level and transform that power to a different voltage level for different purposes depending on the type of the substation.

Types of Substations on Consumers Energy's System

The Company has HVD, LVD, SEC, and mobile substations, which all have a specific purpose. HVD substations receive power from the METC transmission system and reduce the voltage to feed the Company's HVD Lines system, which in turn feed the Company's LVD substations.

LVD substations take power at transmission or sub-transmission voltage levels and step it down to LVD levels, so it can be distributed to households and businesses. **LVD substations,** as shown below in Figure 103, **are the interface point between the HVD and LVD systems.** LVD lines emanate from LVD substations to deliver power to customers.

There is a subset of substations dedicated to serving single industrial customers; these are classified as *Strategic Electric Customer* ("SEC") substations, like the one shown below in Figure 104.

FIGURE 102
HVD SUBSTATION



FIGURE 103
LVD SUBSTATION



FIGURE 104
SEC SUBSTATION



The Company maintains a mobile substation fleet to provide electric service to customers during planned and unplanned substation outages where redundancy is not present or load transfers to adjacent substations are not available.

- Mobile substations are vital to the Company's ability to maintain and operate substations because substation projects and repairs can take several days to several months to complete.

Mobile substations are also deployed to support HVD Line projects, to prevent outages for emergent concerns, and to restore electric service during unplanned outages. An example of a mobile substation is shown in Figure 105.

FIGURE 105
MOBILE SUBSTATION



Number of Substations in Service Territory

The total substation network currently consists of 1,135 Company-owned substations and 64 customer-owned substations.

- The HVD substation network consists of 144 HVD substations and 163 SEC substations.
- The LVD substation network consists of 828 general distribution substations.
- In addition to the Company-owned HVD and LVD substations, there are 35 customer-owned dedicated substations, 5 Company-owned substations providing wholesale distribution services to rural co-op and municipal systems, and 30 customer-owned substations providing wholesale distribution services to rural co-op and municipal systems.
- The mobile substation fleet currently consists of 30 mobile units with varying electrical capacity, electrical configuration, and service function.

Lifecycle Analysis

Substations are a collection of several key components that determine the health and longevity of the Company's substations.

The overall average engineered lifecycle of key substation and mobile substation components average 50 years, including Power Transformers, Circuit Breakers, and Switches.

Safety Risks to the Public

Substations represent a minor public safety risk because of the barriers and fencing surrounding the assets, making accidental public contact exceedingly rare.

In the case of mobile substations, safety barriers can be erected inside of existing substations or outside with fencing.

Substation Asset Health and Risks

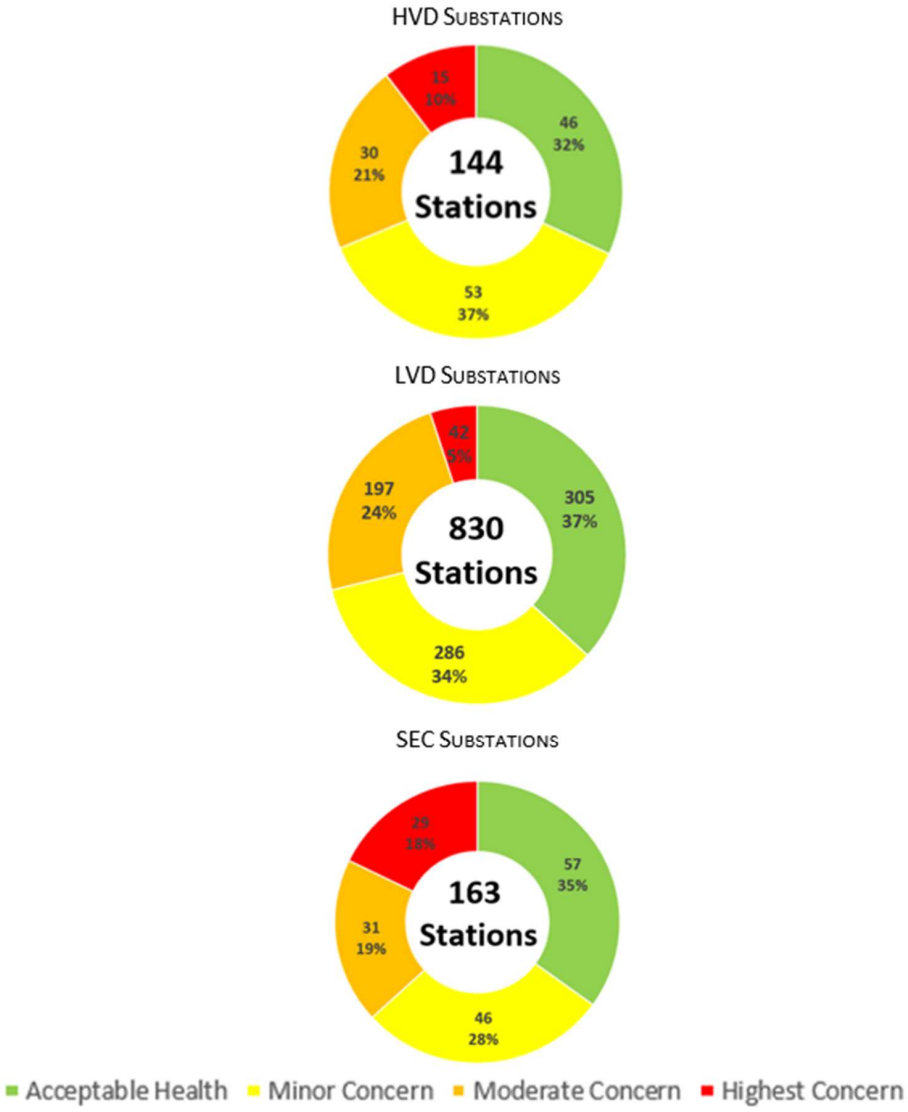
Substation health represents an overall assessment of equipment data and component evaluation for each substation.

Assessments include items such as equipment condition, equipment type, equipment age, visual inspection data, infrared inspection data, oil and gas test data, and electrical test data.

Four health categories have been created with action plans for each color rating as shown in Figure 106.

Figure 106

SUBSTATION HEALTH



HVD Substations

The most recent Company assessment of HVD substation health shows 10% are a high priority for repair and replacement, with another 21% in the moderate concern category.

Of the remaining HVD substations, 69% of substations are in acceptable health or only show minor concerns as shown in the figure above.

Strategic Electric Customer (SEC) Substations

The most recent Company assessment of SEC substation health shows 18% are a high priority for repair and replacement, with another 19% in the moderate concern category.

Of the remaining SEC substations, 63% of substations are in acceptable health or only show minor concerns as shown in the figure above.

LVD Substations

The most recent Company assessment of LVD substation health shows 5% are a high priority for repair and replacement, with another 24% in the moderate concern category.

Of the remaining LVD substations, 71% of substations are in acceptable health or only show minor concerns as shown in the figure above.

Key Substation Risks

Major Equipment Failures

Some substations in the Company's service territory were built in the 1920s and are approaching 100 years in age, and still employ original equipment.

Old and obsolete equipment such as Power Transformers, Circuit Breakers, and Switches can cause large customer outages if they fail, often at a significant cost.

- Failures at HVD substations are less likely to cause customer outages due to the redundancy built into the station design, but when customers are interrupted it can be upwards of 10,000 customers affected.
- Failures at SEC substations will impact only the customer being served.
- Failures at LVD substations are more apt to cause customer interruptions due to less redundancy in the design, but such interruptions typically affect fewer customers ranging from several hundred to a few thousand.

Physical Security Gaps

Animal contacts from birds, squirrels, and raccoons are some of the most common customer interruptions at substations.

However rare, due to the critical importance of substations to the overall electric grid, the Company must also prepare for the case of intentional coordinated attack at these facilities.

- The customer impact of such an attack would be like that of a major equipment failure.
- Opportunities to mitigate this risk are continually being identified and implemented by engineering and operations teams with support from Corporate Security.
- Opportunities include upgrading substation surveillance systems and adding additional security to equipment to prevent inadvertent operation.

Extreme Weather

Extreme heat or cold will increase loadings on substation equipment and may shorten equipment lifespan, which could result in more frequent replacement.

- Extended periods of extreme cold can affect the operation of breakers, circuit switchers, and other electromechanical equipment.
- While substations typically hold up well to violent winds, debris blowing into a station and creating faults in exposed conductors or equipment poses a risk to substations.

Investments to Address Substation Asset Health

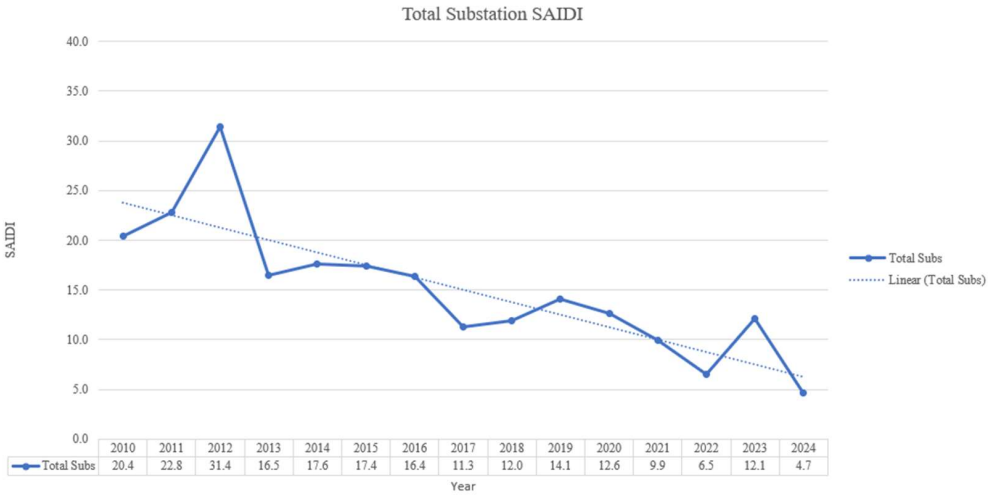
The desired outcome for all substations is to monitor electrical loading, and to provide adequate inspections, maintenance, and end-of-life asset replacement for all substations.

End-of-life is not solely a reflection of asset age. End-of-life is a holistic evaluation of the asset that considers remaining life based on inspection and maintenance findings in addition to the cost of maintaining versus replacement.

The top priority for substations is providing reliable electric capacity to all customers through timely resolution of equipment loading and substation health concerns, new electrical load connections, and substation reliability improvements.

Like HVD Lines, Figure 107 below shows the reliability performance of substations has steadily improved due to the Company's investment in equipment replacement and animal mitigation for both LVD and HVD lines substations.

FIGURE 107
SUBSTATION SAIDI PERFORMANCE



The Company has shown that substations, if properly maintained, can operate beyond their average lifespan. However, these assets must be monitored, inspected, and maintained regularly, and repaired in a timely manner if a failure does occur.

To ensure optimal performance and operation of substations, the Company carries out the following actions to properly protect and maintain substations:

Repairing and Replacing Deteriorated Assets

The Company regularly reviews reliability data, inspection data, industry practices, and operation practices to identify end-of-life assets and modernization opportunities to improve overall customer service reliability, improve substation health, and mitigate customer outage risk.

Based on this data, the Company plans to rebuild substations that are at end-of-life or have working clearances that do not meet current standards and operating practices.

- The Company plans to rebuild over 70 substations over the next 5 years, accounting for HVD, SEC, and LVD substations.
- The Company will also purchase six new mobile substations to support planned and emergent projects that improve customer reliability and substation health, and to support outage prevention and outage restoration.

Where possible, the Company seeks to repair and replace degrading assets to prolong the substation lifespan and reduce cost to customers. The Company regularly reviews reliability, inspection, and operating data to identify where substation equipment is degrading, has reached end-of-life, or requires modernization.

Based on this data, the Company plans to replace equipment to mitigate customer outage risk and to resolve decreased service quality.

- The Company will replace degrading equipment such as transformers, breakers, regulators, switches, and reclosers as concerns are identified.
- The Company will replace all transformers and circuit breakers that are beyond end of life.
- This plan will replace an average of 2 HVD transformers, 10 SEC transformers, 30 LVD transformers, and 40 circuit breakers per year over the next 5 years to support the Company's Reliability goal.

Operations and Maintenance

The Company uses maintenance standards for both LVD and HVD substation equipment, referred to as the *Electric Substation Reliability Guidelines* or (ESR-1) that were developed based on vendor recommendations, industry best practices (including EPRI and IEEE) and collective experience by Company personnel. The recommended maintenance activities outlined in ERS-1 are shown in Figure 108 below.

FIGURE 108

ESR-1 RECOMMENDED SUBSTATION MAINTENANCE ACTIVITIES

Category	Activity
NERC/HVD/Strategic Substations	NERC/HVD/strategic substation inspections (monthly)
	NERC/HVD equipment test operating & profiling (annual)
	Motor Operated Air Break (MOAB) switch test operating (annual) and battery exchanges (every 4 - 5 years)
	NERC/HVD/strategic substation infrared inspections (annual)
	NERC required testing and battery maintenance (annual)
	Strategic customer online insulator cleaning (annual, select customers)
	HVD infrared inspections (annual)
	SF6 breaker gas quality testing
	HVD breaker inspections and maintenance
	Circuit switcher inspections and maintenance
	Spring operated ground switch inspections and maintenance
	Capacitor bank inspections and maintenance
	Transformer Load Tap Changer inspections and maintenance
	Station power transformer inspections and maintenance
Category	**Activity**
LVD Substations	LVD substation inspections (bi-monthly)
	Single-phase regulator maintenance
	Single-phase regulator oil samples and dissolved gas analysis (5-year program)
	LVD substation animal mitigation inspection (twice per year, Spring and Fall)
	LVD substation equipment test operating (annual)
	LVD infrared inspections (every other year)

Category	Activity
All Substations	Emergent and planned 'Broke-fix' work for NERC/HVD/Strategic/LVD substations and Metro
	Infrared repairs (Priority 1)
	Third-party switching and tagging support (strategic customers, ITC, third-party generation)
	Substation transformer oil sampling and analysis (annual), Total Combustible Gas testing (annual)
	Substation snow plowing (Every winter)
	Substation weed control (1 application per year)
	Substation mowing (typically twice per month per sub OR more frequent)
	Substation property clean-up and repairs (trash cleanup, homelessness encampment cleanup, control house repairs etc.)
	Misc. items such as: Substation eye wash station cartridge replacements (annual); switch stick, personal protective ground testing and fuse testing (annual)
	Misc costs (fleet loadings, access control/telecom costs, Doble Engineering membership etc.)
	Power transformer inspections and maintenance (limited by outage availability)
	Infrared repairs (Priority 2 and 3)
	Switch repairs
	Facilities O&M repairs

Funding for the O&M standards in ESR-1 provides increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation at a reduced cost by avoiding emergency repairs, which can cost up to 70% more than proactive maintenance. Additionally, the Company's O&M plan **extends the life of assets by avoiding emergent capital replacements** and allowing for more predictable future capital investments.

The Company has seen continued reduction in SAIDI minutes because of an increased operational focus on preventative maintenance.

Despite the encouraging trend in SAIDI, the *Resilient Grid Plan* will require additional O&M funding to sustain this trend, execute required preventative activities, and continue to improve the internal processes to enhance asset management.

Physical Security Gaps and Animal Mitigation

All substations are enclosed within a fence or wall barrier to provide physical security and public safety, and additional measures are installed to mitigate animal intrusions that can result in substation outages.

The purpose of the Company's animal mitigation is to keep large and small animals out of the substation, and to insulate equipment to extend touch potential if an animal gets into a substation, with specific measures chosen based on substation characteristics.

The Company's current animal mitigation standards were developed based on research conducted at Michigan State University, experiments conducted at the Company's Marshall Training Center, utility industry reports and best practices (e.g., EPRI), and experience gained from previous animal mitigation projects.

The Company's animal mitigation measures include:

- 1-inch mesh fence (squirrels can squeeze through larger mesh)
- Concrete gate foundations (minimizes gaps and frost heave that create gaps over time)
- Polycarbonate panels (3-foot panels installed at the top of the fence to mitigate animals from climbing over the fence)
- Pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation)
- Interior and exterior stone (eliminates gaps at the fence bottom to mitigate animals from crawling under the fence)
- Bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components if an animal climbs on equipment
- Vegetation management

Animal-caused outages are typically the highest contributor to substation SAIDI, leading the Company to aggressively update animal mitigation at the LVD substations.

Approximately 90.2% of the LVD Substations now have standard animal mitigation measures installed. The Company plans to have animal mitigation installed at 99% of the LVD Substations within the next 5 years.

Distribution Supervisory Control and Data Acquisition ("DSCADA")

DSCADA is **the key component of substation automation, allowing the Company to monitor and control substation devices remotely** without requiring the dispatch of a human operator.

When DSCADA is installed at a substation it includes a Remote Terminal Unit (RTU), a local device that facilitates communications with substation devices and remote software systems and captures over 300 data points.

- The enhanced visibility into substations and the remote-control capabilities allow the Company to address outages more quickly and effectively.
- The enhanced visibility also allows the Company's planning engineers to perform more accurate load flow studies because DSCADA provides access to real-time circuit data.

The remote-control aspects of DSCADA are crucial in enabling advanced automation such as the ATR loops described earlier in the Resiliency Investments section of this plan.

The Company plans to install DSCADA at 100 more substations over the next 5 years.

5-Year Investment Plan

For HVD and SEC Substations, the Company is working through a comprehensive plan to replace components that have failed inspections results and are at end-of-life, and rebuild whole substations where needed.

The plan requires $69 million of capital investment per year until 2035, along with a ramp-up of two years until fully implemented.

Also included is an increase in O&M spending across all Substation Reliability and Demand Failures programs to adhere to the recommended maintenance intervals as defined in ESR-1, provide best practice maintenance of all major equipment, and eliminate the backlog of inspection and repair orders.

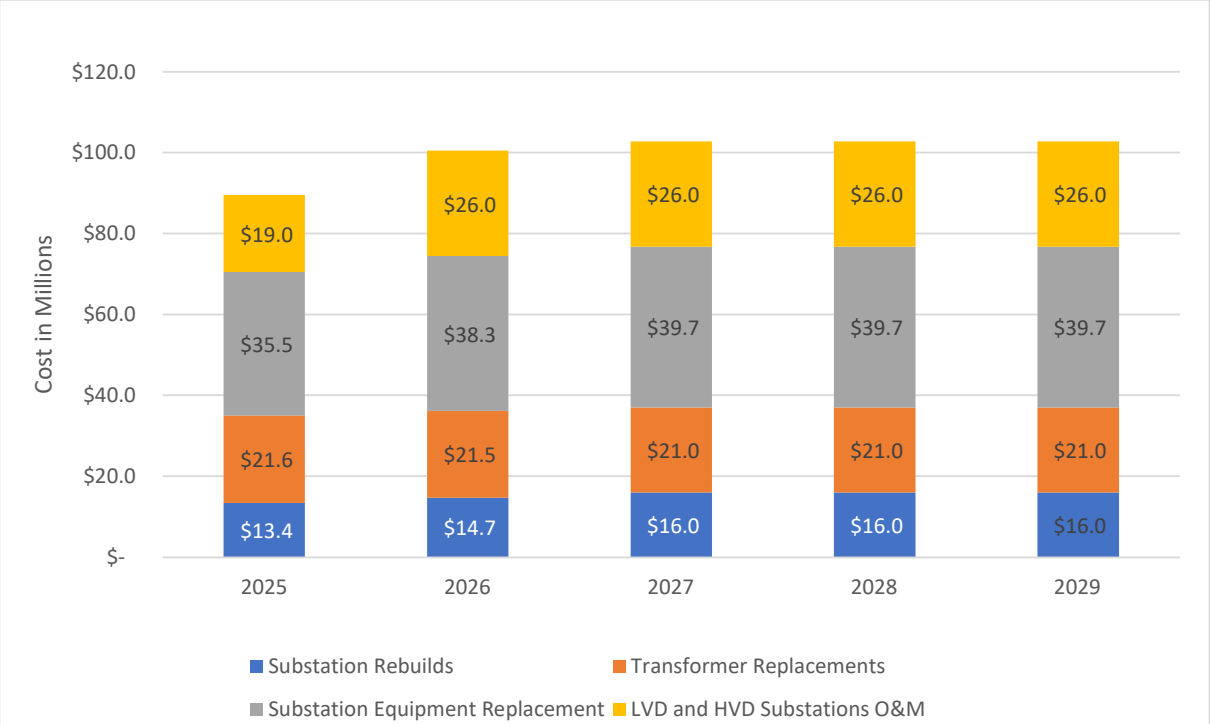
The O&M for both HVD and LVD substations are included in the HVD Substation investment plan below.

- As shown in Figure 109 below, over the next five years this plan will, on average, rebuild 2-4 HVD or SEC substations per year, replace 2 HVD transformers per year, 10 Strategic Customer transformers per year, and 130 piece of substation equipment like breaker, switches, and capacitor banks to support the Company's Reliability goal.

The reliability impact of this work is estimated to result in two fewer HVD or Strategic Customer Substation outages per year.

Figure 109

HVD & SEC SUBSTATION INVESTMENT PLAN



Year	Substation Rebuilds	Transformer Replacements	Equipment Replacements
2025	2	9	220
2026	2	3	190
2027	2-4	12	190
2028	2-4	12	190
2029	2-4	12	190

For LVD Substations, the Company is working through a comprehensive plan to replace components that have failed inspections results and are at end-of-life, rebuild substations, and build new substations where needed.

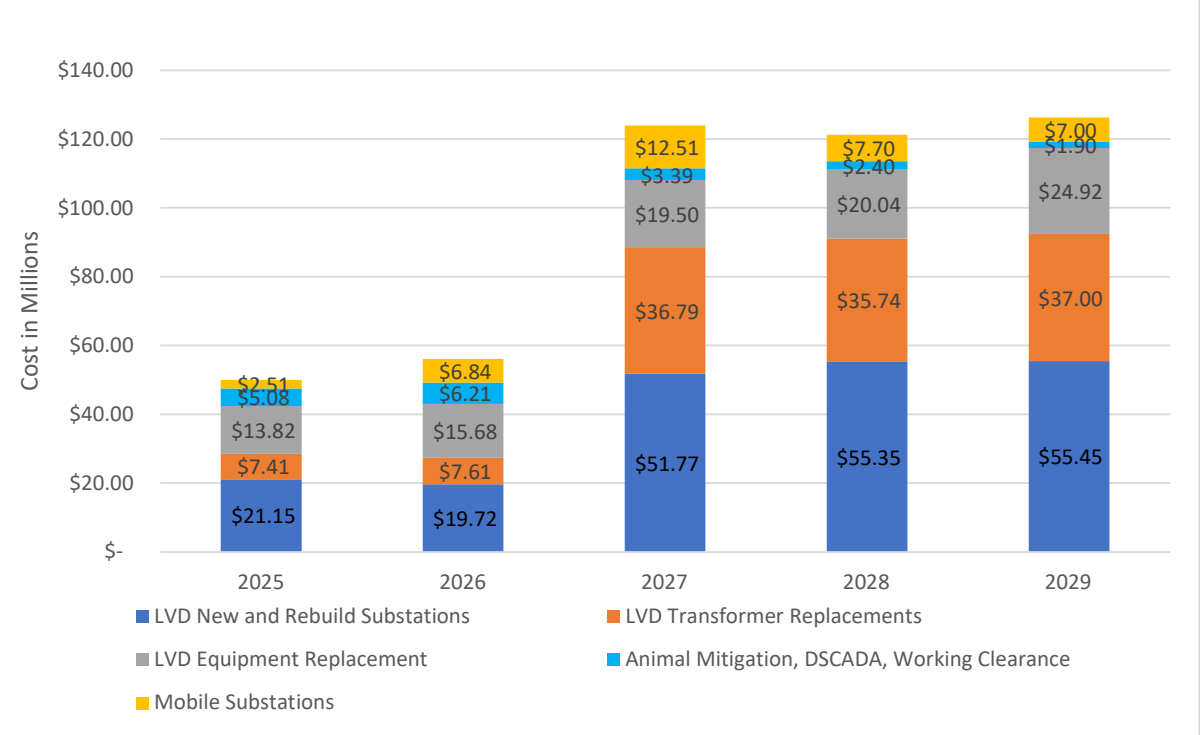
This plan will continue to maintain substations with industry best practices while installing DSCADA at substations for efficient control and monitoring.

- As shown in Figure 110 below, over the next five years this plan includes the building of 20 new substations, the rebuild of 58 substations, the replacement of 151 substation transformers, and the replacement other substation equipment (regulators, reclosers, switches, etc.) to support the Company's Reliability goal.

The reliability impact of this work is estimated to result in two fewer LVD Substation outages per year.

Figure 110

LVD SUBSTATION INVESTMENT PLAN



Year	New & Rebuild Substations	Transformer Replacements	Equipment Replacements	Mobile Substations
2025	13	7	20	2
2026	12	6	15	2
2027	16	35	15	3
2028	17	30	15	2
2029	15	34	15	1

System Protection Relays

What Protective Relays Do

The purpose of a protective system is to **de-energize as quickly as possible** the minimum amount of the electric network that has experienced an electrical fault, to **isolate the fault**, and **mitigate damage** to other equipment.

Protective systems within a substation consist of protective relays designed to trip a circuit breaker when a fault is detected.

Protection systems have two modes of failure.

- The first is **incorrect operation**—when a protective device operates when it should not. This failure mode can cause unnecessary customer outages, and in severe cases, can lead to cascading outages that result in widespread blackouts.
- The second failure mode is **when a protective system does not correctly de-energize an electrical fault**. The failure of a relay to trip properly under fault conditions can lead to severe system consequences, including an extended outage, more customers interrupted than are necessary, equipment damage as lines or transformers burn up, environmental hazards due to ruptured transformers, and public safety hazards due to fires, shrapnel from exploding equipment, and electric shocks due to uncleared electrical faults. Proactively identifying and replacing relays that are prone to failure greatly reduces the risk of these consequences.

Number of HVD Relays in Service Territory

There are 5,237 relays in the Company's service area. A relay unit is defined as a relay panel consisting of 5 electromechanical relays, 10 solid state relays or 2 digital relays.

Lifecycle Analysis

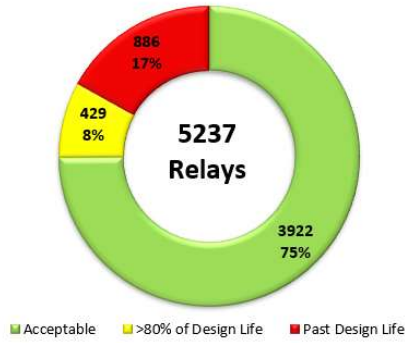
The Company has determined design life for protective relays based on vendor recommendations, industry best practices as documented by the IEEE Power System Relaying Committee, and Company experience with failure of specific relay types.

Protective Relay Asset Health and Risks

The most recent Company assessment of Relay health shows 83% of relays are in acceptable health or have not yet reached the end of their lifecycle, as shown in Figure 111 below. Of the remaining relays, approximately 17% of the protective relay population is older than the designated design life.

As relays age, they are more frequently out of settings tolerance, which can cause interrupting devices (like circuit breakers, circuit switchers, etc.) to open when they don't need to, leading to interruptions, or, not open when they should, leading to larger scale interruptions, equipment damage, and possible safety hazards. More frequent field testing and calibration is required to ensure proper performance.

FIGURE 111
RELAY HEALTH ASSESSMENT



Investments in System Protection Relays

The Company's primary desired outcome for relay health and reliability is to keep all protective relays within design life.

Relay Replacement Plan

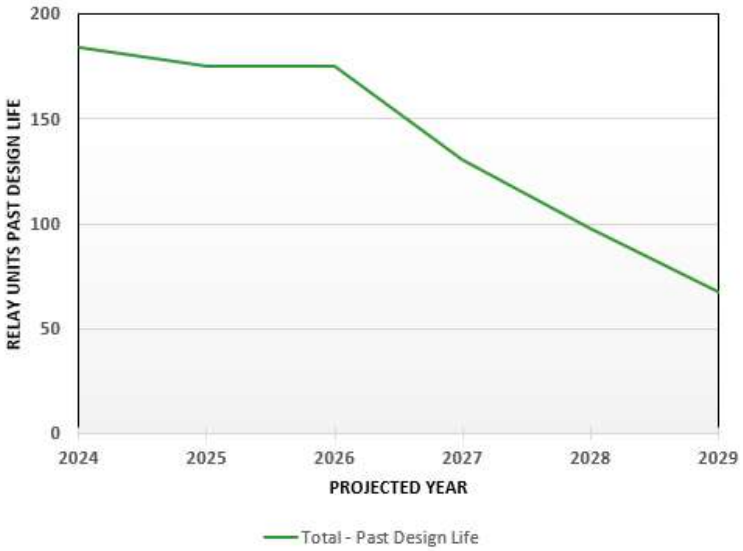
The relay replacement plan is a capital program to replace end of life relays with new modern relays. Multiple factors are considered to assign a risk score to each relay.

- The factors considered include relay age, relay types with a history of malfunctions, substations without digital oscillography, etc.
- The relays are then prioritized based on this risk ranking for capital replacement.

Figure 112 below shows the projected number of relay units that are past design life based on the proposed capital relay replacement plan.

The relay replacement plan will maintain all relays within lifecycle by 2032.

FIGURE 112
PROJECTED NUMBER OF RELAY UNITS PAST END OF DESIGN LIFE



Operations and Maintenance

All relays on Consumers Energy's HVD system are tested and maintained on periodic intervals, and all testing done on the relays is based on manufacturer recommendations.

The intervals are based on the type and function of relay, informed by best practices as defined by NERC Standard PRC-005, and trends observed from historical testing data.

Relays that test out of tolerance are recalibrated or replaced as necessary.

Event Analysis & Corrective Actions

The Company investigates every event on the HVD System to ensure correct operation of the protective systems.

- For all incorrect operations, the immediate cause is identified and resolved.
- For any systemic problems identified, long term corrective actions plans are developed.

System 5-Year Investment Plan

The Company will implement the relay replacements identified above, which requires $5.41 million in 2025, and $4.07 million in 2026, in capital investment.

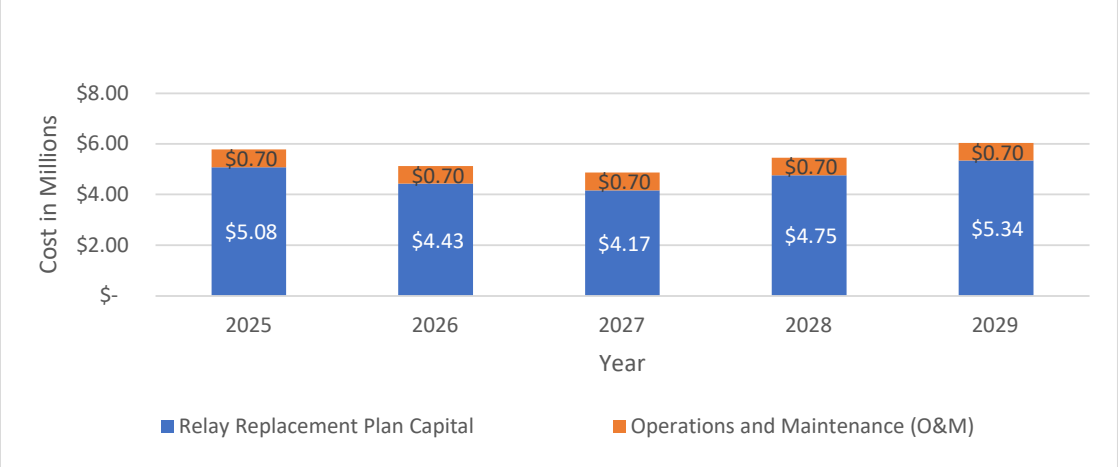
In 2027, the annual spend will increase with inflation as shown in Figure 113 below. The annual investment will increase by $500,000 in 2028 and 2029.

This plan will replace approximately 47 relay units in 2025 and 36 relay units per year in 2026 and 2027. The number of relay units replaced increases to 41 relay units in 2028 and 46 relay units in 2029 to account for digital relays beginning to reach end of life.

The ongoing operational maintenance and corrective actions described above will require $700,000 in 2024, and beyond.

FIGURE 113

SYSTEM PROTECTION INVESTMENT PLAN



Year	Relay Replacement Plan
2025	46
2026	31
2027	36
2028	41
2029	46

HVD Load Growth and Interconnection

HVD Load Growth and Interconnection projects consists of the following:

- HVD enhancements to ensure the HVD system can serve electric peak demand in accordance with HVD planning criteria
- Work to accommodate new interconnections
- Work to improve functionality through standards
- Upgrades to protection
- Operability of the system
- Coordination with transmission infrastructure additions

HVD Load Growth and Interconnection also supports Real Estate and ROW acquisition supporting projects.

Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid.

Investments in this sub-program improve system reliability by preventing future overloads. These investments also help avoid dangerous wire downs and equipment failures due to overloads and exceedance of equipment interrupting capability, improving system safety.

Investments for HVD Load Growth and Interconnection

The Company's primary desired outcome for HVD Load Growth and Interconnection is to ensure the HVD system can serve electric peak demand in accordance with HVD planning criteria, accommodate interconnections to the HVD system, and ensure current standards to support improved functionality of the system.

Load Carrying Capabilities and Voltage Support

Load Carrying Capabilities and Voltage Support projects eliminate unacceptably low voltage, and loadings above line and equipment ratings.

The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system.

New Interconnections

The New Interconnection category encompasses **new interconnections to other utilities and to generation facilities** that must be completed as requested by the interconnecting party.

Costs to interconnect other utilities and generation facilities to the Company's HVD system are reimbursed by the other utilities or generators being interconnected.

Improved Functionality

The Improved Functionality category comprises **projects completed to meet changes in standards, and upgrades** to protective schemes on a planned basis over a period.

- An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period.
- These projects are often coordinated with other major projects when they occur at the same location.

Configuration changes to improve operability are made at the request of the Grid Management group or through coordination with other major projects when they occur at the same location.

Coordination with Transmission

The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that require the HVD upgrades to be completed.

These are completed as needed over time, in conjunction with the transmission owner.

Right of Way ("ROW") Procurement

ROW Procurement projects are necessary to **procure HVD line rights or substation sites for new and/or expanded HVD facilities, as well as rights necessary to maintain existing HVD facilities**. These projects are critical to prepare for HVD construction and for maintaining existing HVD facilities ,and can require significant lead time.

Acquiring the necessary land or land rights is integral to advancing HVD lines and substation projects.

These projects must be prioritized to adequately support the project that is depending on the new rights (e.g., new HVD line, HVD line relocation or rebuild off-center, new HVD or LVD substation, or improved easements where rights are determined to be inadequate).

Through the process of monitoring and studying load profiles, properties are sought and procured to build electric infrastructure at the right point in time needed to serve customers.

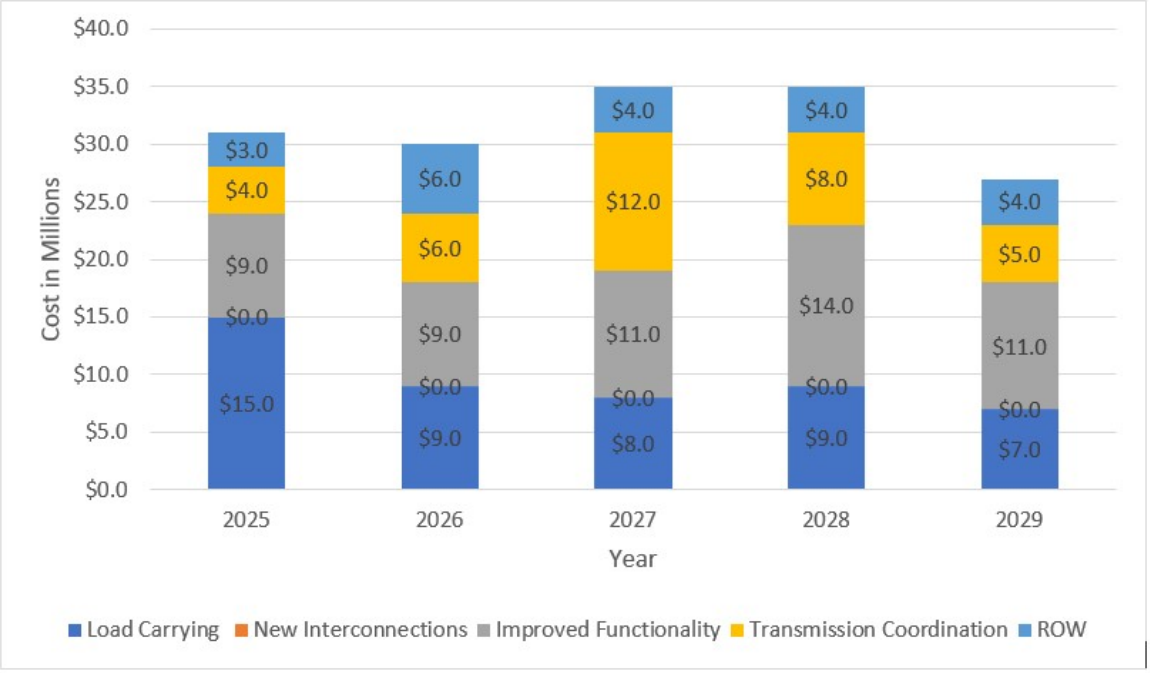
HVD 5-Year Investment Plan

The Company's investment plan is projected to cost $140 million over the next five years.

The 5-year investment plan (shown below in Figure 114) will ensure that the HVD system has the capacity to accommodate peak system load including potential changes to load profiles needed for new and changing technologies, maintain safety and reliability, and accommodate interconnection to the system.

Figure 114

HVD LOAD GROWTH AND INTERCONNECTION 5-YEAR INVESTMENT PLAN



***NOTE:** New Interconnections is listed above as $0 and not listed in the unit table below because the projects expected in 2025-2029 in that category will be 100% reimbursed. Also, ROW projects are not listed in the unit table below as these projects vary in scope/size/timing such that units are not readily available

Year	Load Carrying Projects	Improved Functionality Projects	Transmission Coordination Projects
2025	4	18	11
2026	4	14	8
2027	3	15	12
2028	3	15	8
2029	3	15	8

Additional Topics

Streetlighting

What Streetlights Do

Streetlights provide illumination to enhance safety and the aesthetics of roadways, residential areas, and cityscapes in various applications throughout the Company's service territory. The Company operates and maintains all Company-owned lighting.

Quantity and Technology of Streetlights in Service Territory

Consumers Energy owns and maintains approximately 173,000 streetlights. Most of these streetlights are cobrahead fixtures (see Figure 115 below for streetlight fixture count). Cobrahead, Center Suspension, and Post Top fixture examples are shown in Figure 116.

FIGURE 115

STREETLIGHT FIXTURE COUNT

Fixture Type	Count
Cobrahead	119,000
Post-Top	43,000
Center Suspension	11,000
TOTAL	**173,000**

Figure 116

EXAMPLES OF STREETLIGHTS

Cobrahead Streetlight Fixture



Center Suspension Fixture



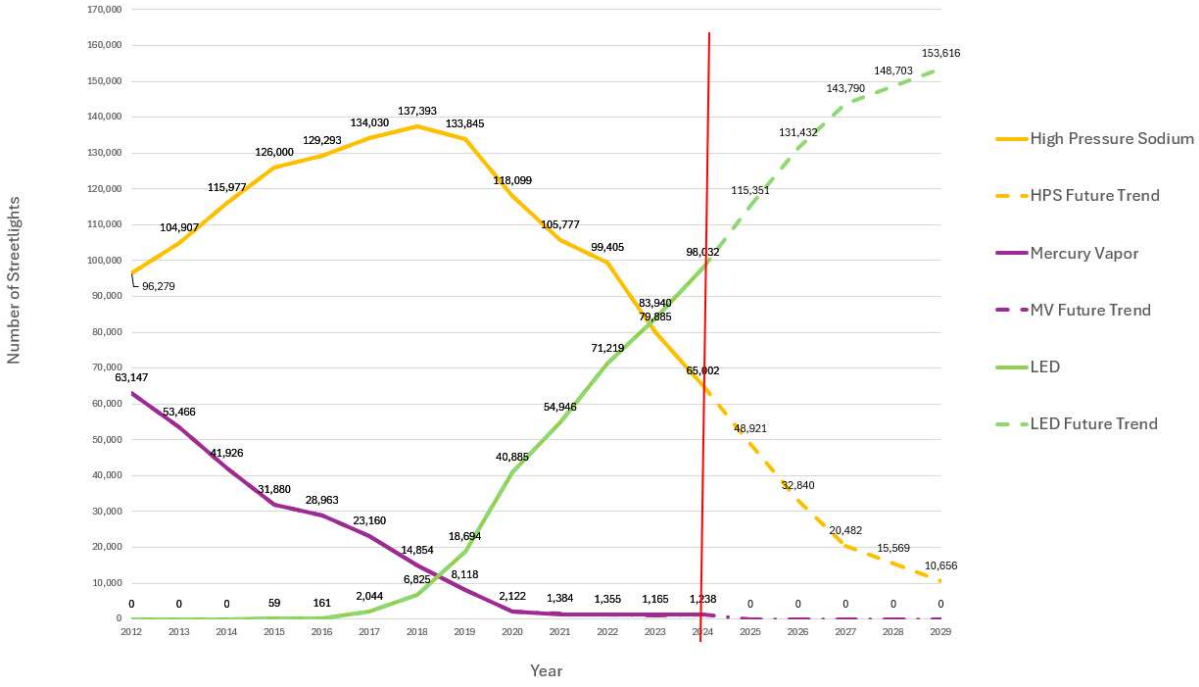
Post-Top Fixture



The Company's streetlighting portfolio includes three types of fixtures: *High Pressure Sodium, Mercury Vapor,* and *Light Emitting Diode* technology.

Figure 117 below represents historical and projected technology trends. The trends reflect the Company's transition from *High Pressure Sodium* fixtures to *Light Emitting Diode* fixtures due to the increase in efficiency.

FIGURE 117
Streetlight Technology Trend



Lifecycle Analysis

The shortest lifecycle component of a streetlight is the *lamp*, which drives the useful life of a streetlight.

- Lamps on the high intensity discharge ("HID") fixtures are rated for 24,000 hours of service.
- With approximately 4,200 hours of lighting service annually, the average life of the lamps in HID fixtures is approximately six years.
- Newer lighting technology light emitting diode ("LED") fixtures are more efficient and are rated for 84,000 hours of service bringing the average life of a LED fixture to 20 years.

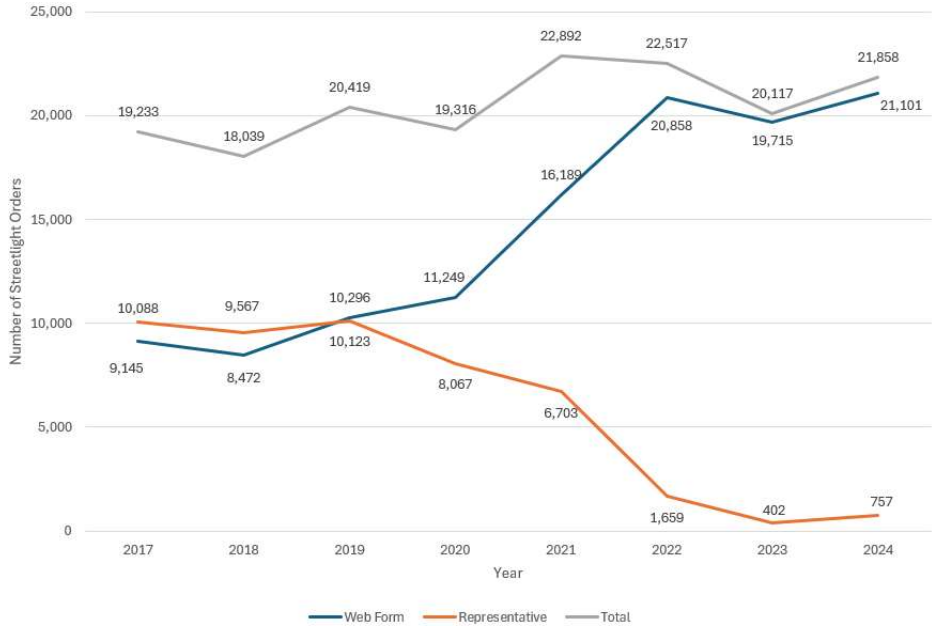
Streetlight Asset Health and Risks

As shown in Figure 118 below, approximately 22,000 streetlight outages and issues are reported each year.

- Non-third party related primary causes of streetlight outages are attributed to bulb failures.

FIGURE 118

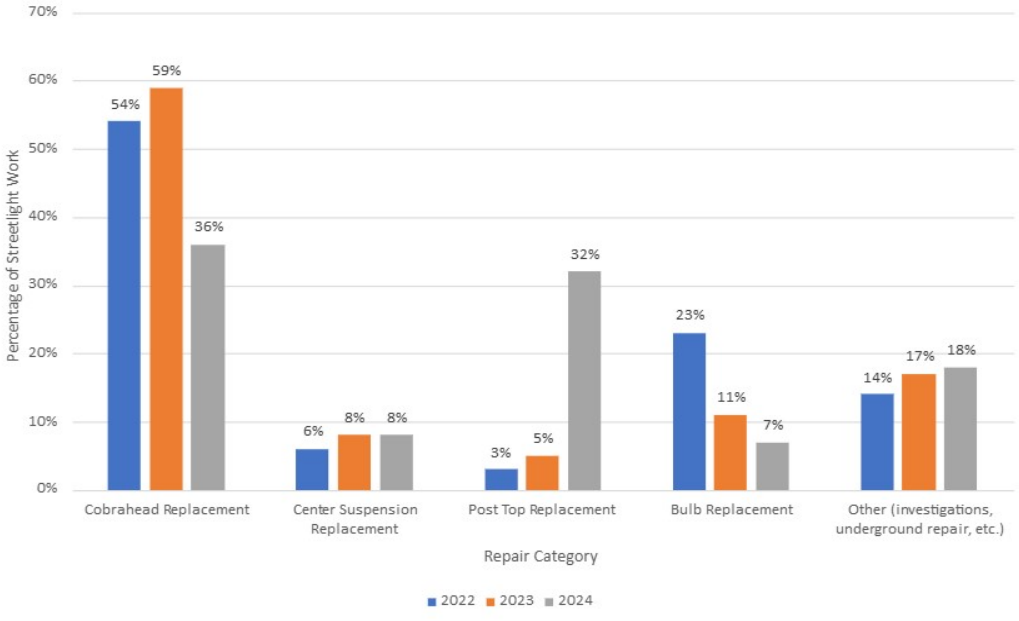
Streetlight Orders by Creation Type



A breakdown of *work type* is shown in Figure 119 below.

FIGURE 119

WORK TYPE BREAKDOWN OF STREETLIGHT ORDERS



Workplan

The ideal state for the Company's Streetlighting program is to repair or replace streetlights only at the end of the component lifecycle. Extending the lifecycle of the luminaire reduces repair expenses across the Company's streetlight portfolio.

LED Conversion of HID lamps across all applications reduces the frequency of bulb-related outages.

To facilitate this, cobrahead, center suspension, and post-top HID installations are being converted to LED technology upon failure.

In addition, vicinity conversion tactics will be used for Cobrahead and Post-Top installations. Vicinity conversions upgrade in-service HID lighting in the vicinity of a failed luminaire, and this reduces costs per conversion by reducing frequency of repair worker mobilization to the same area.

Streetlight 5-Year Investment Plan

The Company will complete vicinity conversions across cobrahead and post top lighting types.

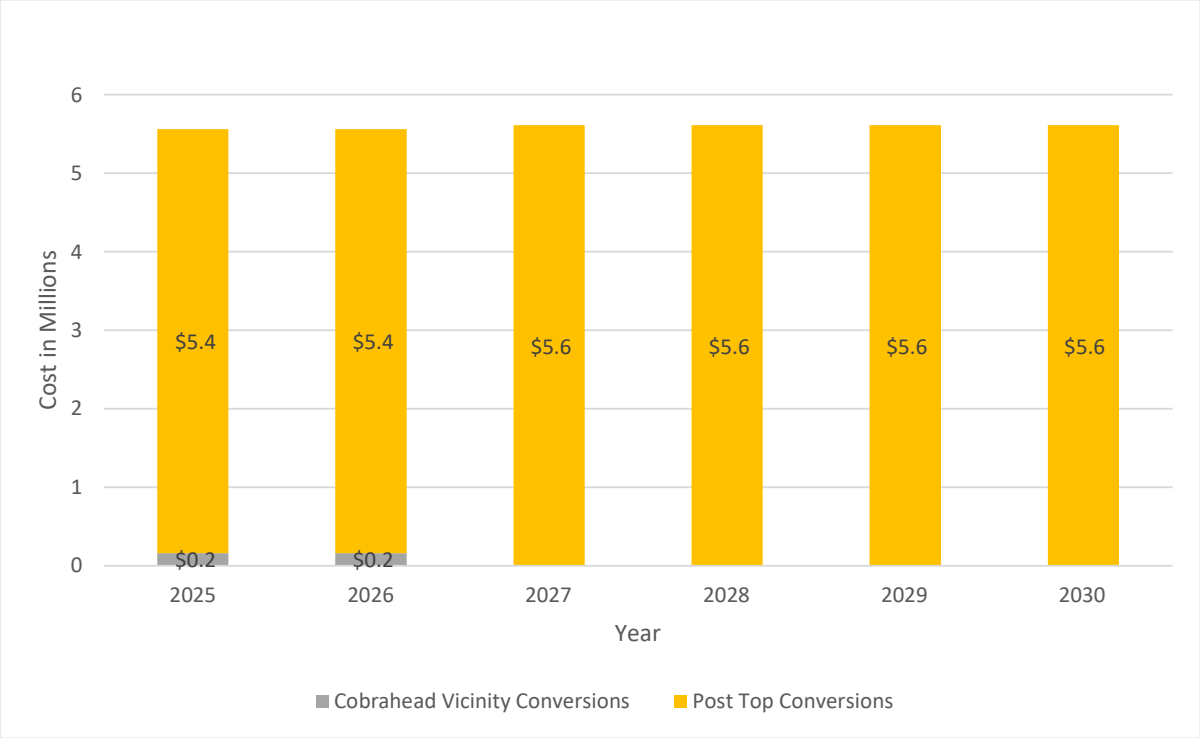
- The Company estimates 11,100 HID cobrahead lights will be converted to LED technology through reactive conversion and 260 HID cobrahead lights will be converted to LED technology through vicinity conversion, annually.
- The Company estimates all Cobrahead fixtures will be converted to LED technology near the middle of 2027. This plan will cost $0.4 million over two years.
- The Company estimates 3,910 HID post top lights will be converted to LED technology through reactive conversion and 800 HID post top lights will be converted to LED technology through vicinity conversion, annually.
- The Company estimates all post top fixtures will be converted to LED technology by mid-2033. This plan will cost $47.5 million over the next nine years.
- Post top vicinity conversions will increase to 1,000 annually once all cobrahead lights are converted to LED technology.

Failure costs of streetlight assets are expected to be reduced following the completion of LED conversions. The 5-year investment plan for streetlighting is shown below in Figure 119.

Figure 1219 includes vicinity conversion of cobrahead streetlights, reactive conversion of post top streetlights (began in 2024), and vicinity conversion of post top streetlights.

Figure 119

STREETLIGHTING INVESTMENT PLAN



Year	Cobrahead Vicinity Conversions	Post Top Conversions
2025	260	4,710
2026	260	4,710
2027	0	4,910
2028	0	4,910
2029	0	4,910
2030	0	4,910

Grid Automation

Grid Automation (formerly "Grid Modernization") operationalizes proven technology to enable a reliable, resilient and automated electric grid that is secure and affordable for customers. Grid Automation delivers for the future grid by **incorporating new technologies and applications into the electric system to increase reliability**; **optimizing energy delivery**; and facilitating the **optimal use of DERs**.

While many utilities share common themes for defining Grid Automation, every utility has a unique approach for implementing and enabling Grid Automation capabilities due to their unique customer, geographical, operational, regulatory, and business needs.

- Grid Automation plans include **standardization and deployment of new proven technology** in substations and on electric lines.
- Also included is the **development of new tools and systems** to improve the way the Company monitors, controls, and optimizes assets.

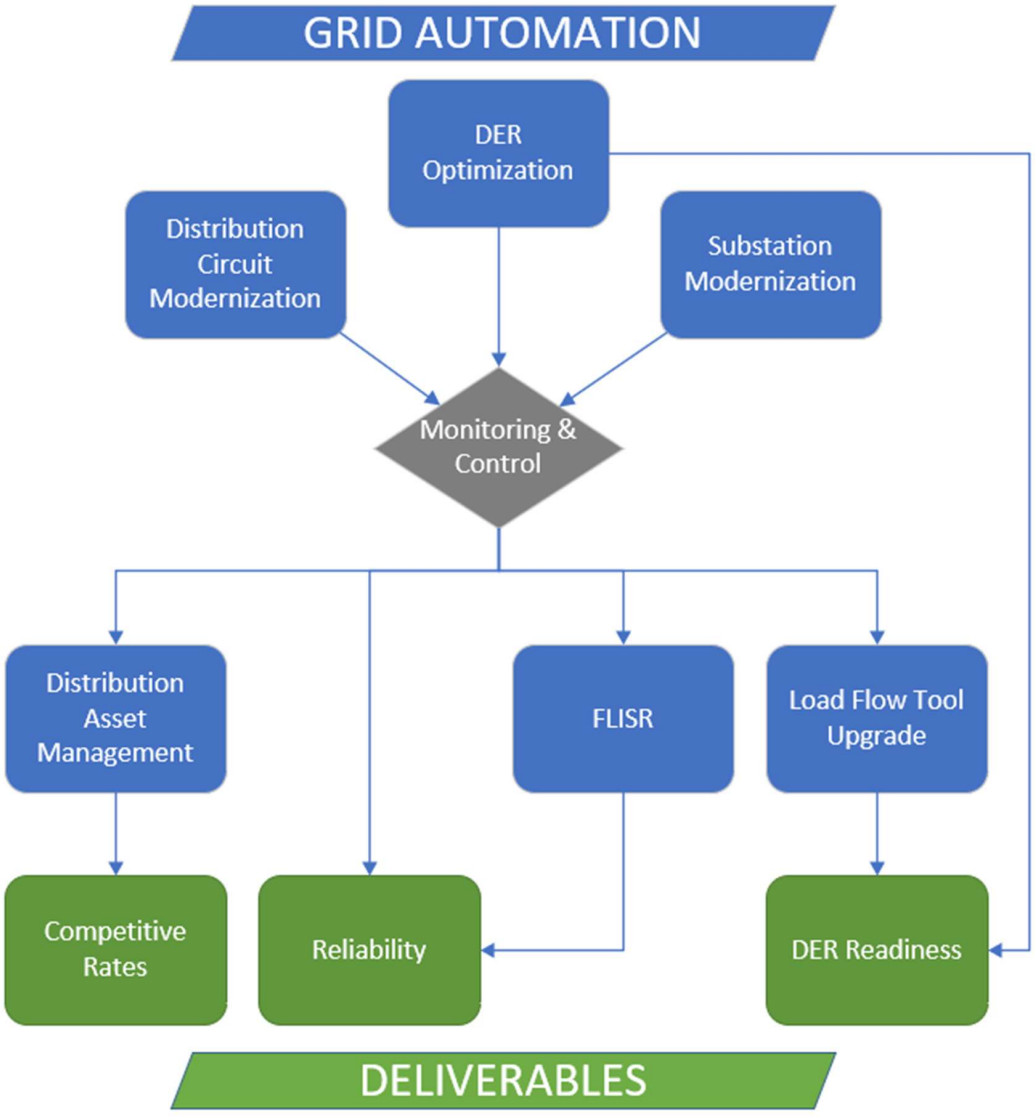
The Company continues to invest in new technologies and digital tools to build for the future through research, testing, and development of modern grid technologies that support key Company objectives.

To support enabling these capabilities and the overall Reliability Roadmap, the Company's Grid Automation organization is planning to develop a Grid Automation 5-year Strategy. This will inform future rate cases and needed investments by benchmarking the industry to help sequence new technology in a way that provides optimized benefit for customers.

As seen in Figure 120 below, the foundational technologies of Grid Automation enable monitoring and control of the distribution system. With increasingly wider monitoring and control, several other key Grid Automation systems gain connectivity to the grid, which is needed to deliver further benefits beyond the sum of the foundational technologies' parts.

All these initiatives significantly affect key Company deliverables such as reliability, competitive rates, and DER readiness.

Figure 120
Grid Automation Deliverable Mapping



New technologies are run through a robust *Technology Enablement Process* ("TEP") (see Figure 128 below) to ensure all facets of the technology solution are ready for use by Company stakeholders when the solution has reached go-live.

Figure 121
High-Level Technology Enablement Process



Distribution Circuit and Substation Modernization

There are many opportunities to improve substations and distribution lines to be ready to support the needs of the future grid. Therefore, Grid Automation continues to participate in utility research projects and innovation forums to understand utility best practices and identify the best technology approach for the distribution system.

- As **new LVD technologies** are shown to provide utility value, the Company considers including them within the strategic **Distribution Circuit Modernization ("DCM") roadmap,** a long-term plan to enable new technologies that build on the learnings and capabilities of others in the DCM roadmap. The DCM roadmap is a living document that evolves based on those learnings, as well as align with utility industry best practices and research.
- Similarly, the **Substation Modernization** program maintains a strategic substation technology roadmap with a vision to advance substation infrastructure to the next generation, including IP-enabled networking capabilities. Substation Modernization initiatives will also follow the *Technology Enablement Process* and build out progressively beneficial and interdependent substation systems and devices.

The technologies being pursued on these roadmaps are foundational to support general monitoring and control of distribution circuits and substations, and set the stage for future more complicated automation via ADMS, FLISR, and DER Optimization.

Distribution Energy Resources Optimization

The Company has launched an initiative to standardize and prepare the grid for the anticipated growth of DER, as discussed earlier in the Non-Load Challenges from Customer Technology Adoption section.

The DER Optimization initiative consists of a variety of hardware and software deployment projects to develop, evaluate, and standardize DER management capabilities across the spectrum of DER types.

- Projects will be sequenced so that initial deployments focus on grid-edge capabilities that include DER gateways.
- DER gateways optimize controllable resources based on local conditions, as well as provide communications and translation services to a diverse set of DERs.
- DER gateway projects on the grid-edge include solar arrays, batteries, EV chargers, and circuit-level deployments.
- As DER penetration increases, the Company plans to deploy a centralized DER management system (DERMS) that will provide system-level grid benefits such as peak shaving, market participation and compliance with FERC Order No. 2222.
- A centralized DERMS is critical for managing bi-directional power flows, power quality concerns, and interconnections with third party DER.

- High levels of DER penetration may negatively impact reliability, efficiency, and overall grid performance if not properly monitored and managed.
- The increase of the Distributed Generation program cap from 1% to 10% of the utility's average five-year in state peak load introduced by Public Act 235 escalates the reliability concern and accelerates the timeline for needing to begin DERMS implementation.

The DER optimization initiative will not only mitigate these threats but will lead to future reliability and efficiency improvements. **DER benefits can only be fully realized when they are comprehensively integrated into grid operations.** Therefore, DER must be visible to and controllable by the Company's grid operators to ensure reliable, affordable, and safe electric service.

Distribution Asset Management ("DistAM")

DistAM is the application of **asset management principles and processes to electric distribution assets to maximize the usefulness and realization of value over their lifecycle.**

Previous sections covering LVD and HVD assets described current state asset health and management practices. However, the Company is pursuing a centralized and standardized asset management strategy that encompasses all electric assets in a unified approach.

Our DistAM program will enhance existing lifecycle management capabilities by **collecting key asset data (*e.g.*, age, nameplate data, location) to drive a risk-informed, value-based decision-making methodology** to manage and optimize asset investments. This work is aligned with industry best practices defined in ISO 55001, as well as from the *Michigan Infrastructure Council Asset Management Program*.

Asset Management will standardize the Company's asset life-cycle processes, data, and technology, allowing for improved capture, analysis, and visualization of asset health, which will lead to more optimized investment planning scenarios.

The primary benefits of DistAM include:

- Reduced capital and maintenance costs.
- Reduced customer outages and restoration costs
- Reduced power quality issues and system losses
- Increased asset availability and deferred capital depreciation
- Reduced asset degradation risk
- Improved resilience of the electric distribution system
- Proactive condition-based asset replacement/maintenance

The DistAM strategy identifies three key components that will deliver a robust asset management system. These components are *Asset Repository*, *Asset Performance Management* ("APM"), and *Asset Investment Planning* ("AIP").

These components will leverage collected distribution asset data into a single centralized database, which provides enhanced integration into asset health performance analysis and investment strategy platforms.

- The Asset Repository software release, with four initial assets, is scheduled for the second quarter of 2025. After the software release, asset data can be added incrementally using the standard integration elements being deployed. The Asset Repository can then ingest asset data from other data collection methods to improve asset data quality.

- The APM software calculates asset health scores and utilizes Asset Repository asset data. With the incremental approach of the Asset Repository, the APM will need to accommodate sparse asset data by possibly augmenting static nameplate data with sensor technology. Exploration of automated sensor readings could provide measurements to the APM to improve asset health calculations.
- The AIP solution is now complete. The integration of additional asset data into the Repository and APM will only improve the benefits of the AIP system.

The Company envisions that as the technology of imagery analytics advances, so too will the benefits of DistAM.

DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed.

Realizing the benefits of these assets requires effective management of the electric distribution system, which is the foundation that DistAM provides.

Reliability Analytics Monitoring Program (RAMP) *(formerly Anomaly Detection Analytics)*

The RAMP uses **line sensor data across our LVD and HVD systems to understand whether we are experiencing conditions** (asset deterioration, tree branch interference, etc.) **on our lines that are likely to cause an outage** such as asset deterioration and tree branch interference**.**

These analytics provide an opportunity to send crews to complete work to mitigate these conditions proactively at a lower cost to rate payers as opposed to addressing these in an emergent condition after the outage has occurred.

In 2023, more than 500,000 customer outage minutes were avoided by correcting outages before they happened.

The Company is pursuing a contract to maintain this service into 2025 and beyond. Over the next five years this project is expected to save 1 minute of SAIDI.

Load Flow Tool Upgrade

For nearly 25 years, various planning departments throughout the Company have relied on an industry-standard suite of CYME power engineering software products to assess the current and future health of the distribution system.

The modeling techniques and simulation capabilities enabled within these tools have met the planning requirements of a system with traditionally predictable load and short-circuit conditions but cannot accurately or efficiently capture the time-based complexities introduced by DERs and electrification. See the Challenges from Customer Technology Adoption, and Non-Load Challenges from Customer Technology Adoption sections for further discussion on these challenges.

To begin to address these challenges in planning tools, the Company entered the discovery phase of a Load Flow Tool Upgrade project in 2024, with plans to start developing and enabling advanced forecasting, modeling and simulation capabilities in 2025.

- At a high-level, this initiative will evolve our planning models from a snapshot in time approximation of peak conditions to a digital twin representation of the distribution system capable of identifying system constraints and opportunities for optimization at any hour of the year, under various customer technology adoption, weather, and load growth scenarios.

Planning tool enhancements will allow the Company to make the right infrastructure investment decisions at the right time to maintain the reliability, power quality, and efficiency of the distribution system as customer adoption of new technologies increases. They will also:

- Enable comprehensive review of the fast track and supplemental screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards
- Increase the accuracy and value of the Company's hosting capacity maps
- Support Company compliance with the various distribution system impact analyses and data reporting requirements of the Michigan Transportation Electrification Plan
- Provide planning and interconnection SMEs with the insights needed to successfully navigate the increased Distributed Generation program cap required by Public Act 235.

Fault Location Isolation Service Restoration (FLISR)

The Company worked with EPRI in 2024 to develop a plan for full implementation of FLISR. FLISR consists of both hardware and software.

The hardware consists of communicating reclosers, switches, and line sensors. The Company has made significant progress with the installation of these reclosers and line sensors, and even more potential awaits with the DCM technologies described above including SCADA-enabled reclosers and switches.

The next area of focus in the Company's sequence is to use SCADA controlled switches to further sectionalize circuits, to limit outage impact to customers.

- Within the ADMS software, FLISR will use the communicating reclosers, switches, and line sensors to automatically identify where faults are on the system.
- FLISR can provide automatic functionality to isolate faults before analyzing load transfer potential for the remaining de-energized customers downstream of the faulted section. Additionally, it decreases the public safety risk of encountering energized downed wires. Patrol times and switching times for field crews are also greatly reduced.
- To enable this, updates and enhancements will be required to the ADMS software and to core applications that support ADMS, such as Distribution Power Flow, Substation Model integration, Spectra Insight and a simulation environment for Grid Operators to learn necessary skills before executing on the job.

By 2025, the Company will have deployed more than 12,000 line sensors across HVD and LVD.

These sensors provide optimal coverage of the grid to support the FLISR program. Line sensors are **devices that attach to primary lines to monitor current and faults, as shown in Figure 122.** They detect faults and determine a probable location of an event, making them critical in enabling FLISR.

Line sensors also provide information such as loading, phase balance, momentary outages, line disturbances, and other alarms.

- Line sensors can be used to improve the LVD planning process by providing more accurate load flow modeling. This more precise and real-time load information can be used to improve the load transfer process both for planned and unscheduled outages.
- This tool reduces the duration of the manual load transfer writing process and improve the accuracy of the modeled transfers.

FIGURE 122

3-PHASE LINE SENSOR INSTALLATION



Weather Monitoring

Given the increasingly severe weather Michigan is experiencing, the Company needs the ability to monitor the weather at a localized level.

The current coverage of existing NOAA weather stations leave gaps in the Company's service territory. **To address this, the Company intends to install modern weather stations in 2025/2026 across its service territory.**

The number of weather stations is expected to expand through 2027, providing visibility across the service territory including wildfire risk areas. This will allow for quicker decision-making capabilities to aid in storm preparation and response. This includes repositioning Electric Line Crews to areas that are in a storm path and deploying Damage Assessment teams to survey areas that indicate severe weather based on the weather station real-time data.

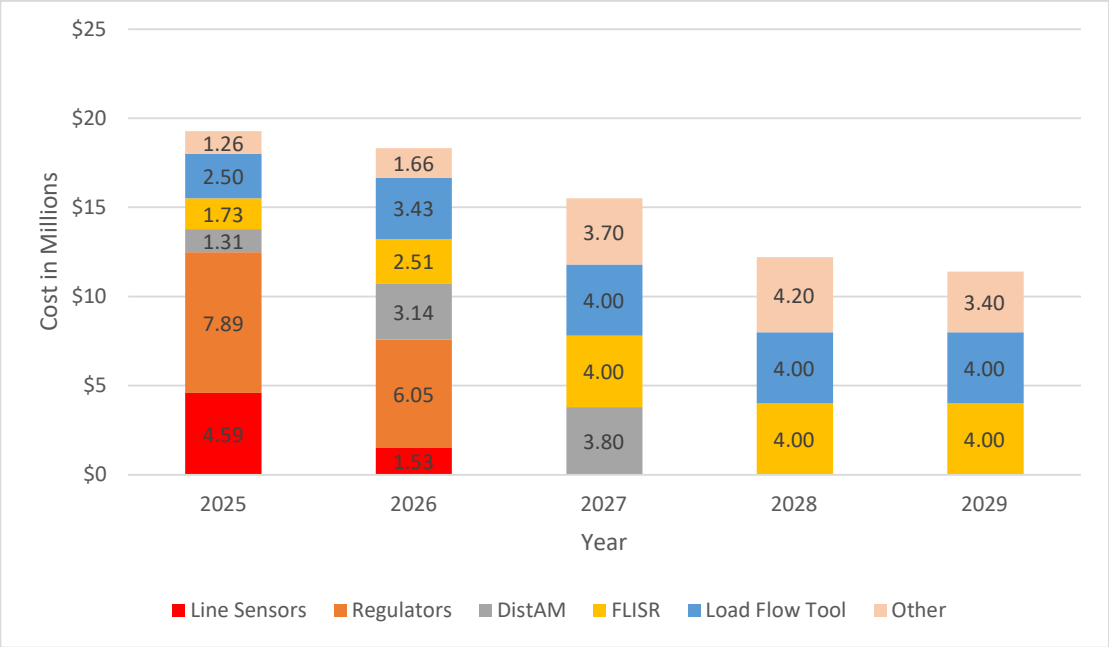
Additionally, the Company will study these localized weather impacts against the performance of the electric assets, informing future resiliency investments. The Company plans to expand the number of weather stations throughout 2027.

Grid Automation 5-Year Investment Plan

Over the next five years, the Company will invest in the automation and modernization of the electric grid through various hardware and foundational software deployments.

This includes deployments of remote-communicating grid equipment such as Line Sensors, Voltage Regulators and Switches. It also includes foundational software deployments such as DistAM and FLISR that prepare the grid for the future.

Figure 123
Grid Automation 5-Year Investment Plan



Year	Line Sensors	Regulators
2025	750	221
2026	250	169
2027	0	0
2028	0	0
2029	0	0

Advanced Distribution Management System (ADMS)

ADMS is the **software platform that supports the full suite of distribution management and outage management** systems.

This platform brings together the Company's Distribution Management System ("DMS"), its Field Mapping Applications, and its Electra Outage Management System ("OMS")—which includes additional outage applications (tools that integrate with ADMS and aggregate outage-related information).

ADMS is dependent on the following:

- Supervisory Control and Data Acquisition or SCADA, as described in the Substations section.
- Geographic Information System ("GIS")
- Advanced Metering Infrastructure or AMI—a two-way communication system that collects detailed metering information throughout the Company's service territory.

ADMS real-time functionality drives improved decisions to make the electric distribution grid more efficient, enabling the Company to get customers' lights on faster.

There are two main enhancements to the ADMS platform planned, along with continued integration improvements with additional outage applications, including:

1. Implementation of the Field Mapping Application
2. Completion of the DMS platform to include:
    a. Fault Location Isolation & Service Restoration ("FLISR")
    b. Switching Order Management ("SOM")

The **Field Mapping Application** will extend the use of ADMS core functionality to the Company's field workforce.

This Application **will improve workforce efficiency by providing field employee precise real-time circuit maps and damage assessment information**.

Real-time damage assessment—when combined with 2024 implementation of Live Wire Down—will **improve customer experience** through the Company's current online outage map while also improving public safety through reduced restoration times.

Completing the *DMS* portion of ADMS will add enhancements focused on implementing all FLISR and SOM software modules. FLISR was described earlier in the Grid Automation section of this document.

- **SOM** is an ADMS **application that generates switching orders for field workers**, which will send automatic control signals via SCADA to perform and verify automatic switching operations. Using point-and-click interaction with graphical applications, a switch order is established and validated against real-time operating conditions via network interface (allowing pre-verification of the order before it is dispatched, saving time in outage response).

In addition to the two primary enhancements, the Company expects to **improve system Reliability and Resiliency through use of automation and digital tools to support ADMS.** Better integration of outage applications not currently incorporated into the Electra OMS or DMS will better integrate real-time data for restoration.

Aside from Reliability benefits, the Company will be less at-risk from catastrophic system failure.

FIGURE 124

ADMS COST and SAIDI

ADMS Enhancement	2023 Capital	2024 Capital	2025 Capital	SAIDI Savings (excluding MEDs)
OMS Electra incl Live Wire Down	$800k	$900k	$0	5 minutes
Field Mapping Application	$0	$1,600k	$0	4 minutes
DMS complete FLISR and SOM				
Outage Applications Integration	$250k	$250k	$0	4 minutes
AMI Automation Use Case	$150k	$0	$0	2 minutes
Total	**$1,200k**	**$2,750k**	**$0**	**15 minutes**

Next Digital Investments

Integrating emerging technologies, data, and analytics for Consumers Energy is instrumental in achieving our Company goals with great precision and foresight.

Our Next Digital Investment strategies provide valuable insights enabling **data-driven decision-making leading to enhanced efficiency, improvement to risk management, and cost reductions**—all to ensure our business remains resilient and reliable in a rapidly evolving digital landscape.

Additionally, using emerging technologies helps provide actional insights to tailor our tools and services to meet customer demands effectively.

By leveraging the next digital investments such as artificial intelligence, machine learning, and automation, we can **optimize processes, identify trends, and improve customer experiences**.

Outage Forecasting Model

Through a partnership with the University of Michigan, the Company is pursuing creating a suite of outage forecasting models. These models will predict customers without power, estimated incidents/trouble spots, wire downs, and poles that require replacement over the upcoming six-day period.

Asset, outage, damage, and weather data will be combined to inform the models and the output will be used to make informed decisions regarding pre-staging and staffing for weather events.

- Models for estimated incidents, damaged poles, and the number of wire downs will be delivered in the second quarter of 2025.

The customers without power model will be delivered in the fourth quarter of 2025.

Productivity & Utilization Analytics (Formerly the Restoration Wait Time Tracker)

In 2023, the Company established a dedicated group to address restoration costs. As a precursor to the Restoration Wait Time Tracker (a tool that will **provide the ability for storm response teams to understand in real-time what is happening in the field** during restoration activities),

- Productivity and Utilization Analytics have been created to measure effectiveness of restoration during storm events in 2024.
- **Work orders, crews, hazards, and outages were combined to provide visibility into the productivity differences between internal crews and contractor crews.** In 2024, post-storm analyses were standardized and real-time capabilities will begin construction in 2025.

Our storm response teams can then see in real-time when and where delays are occurring and take action to resolve barriers. This will lead to faster storm restoration.

This project is expected to result in 0.5 minutes of SAIDI savings and a 12% productivity increase during storm restoration activities.

Catastrophic Crewing Replacement

Catastrophic Crewing (“CatCrew”) is the Company’s 15-year-old home-grown resource management software tool used during storm restoration.

- This tool captures information about who is engaged in storm restoration, the Headquarters they are working from, and their work and rest time periods.
- CatCrew also captures lodging and food requirements needed for resources engaged in storm response.

The CatCrew tool **enables the Company to have a clear and up-to-date picture of resource capacity and engagement**, ultimately leading to a more efficient and faster restoration.

After restoration work is complete, we use the data captured within CatCrew to perform advanced analytics and identify improvement opportunities.

We are pursuing a vendor-provided software product to replace CatCrew due to our current software becoming outdated and difficult to maintain. The procurement of internal and external resources during storm restoration can be a prolonged process and **replacing the current software with a more responsive system will allow us to realize efficiencies** in procuring needed resources.

- Vendor-provided products exist with the functionality we need, including integration with hotels and food providers.
- The Company is in the beginning stages of the Request for Proposal ("RFP") process and estimates this will run through 2023, with selection occurring in first quarter 2024.
- The Company plans to have a new software solution implemented in 2025.

Forestry Workplan Intelligence & Strategy Engine ("WISE") Phase 2

As discussed in the *Forestry Line Clearing Program* section, the Company is working to enhance its use of advanced technology in this space.

In 2025, an internal team will be updating the Forestry WISE model to provide the annual LVD full circuit clearing workplan at the LCP-level. Once completed, this will enable the Company to be more strategic in forestry work selection, driving the replacement of reactive analysis with predictive analysis.

Imagery Analytics

The Company will re-imagine the inspection process across the various energies, **using drones and other image capture technology in a much more intentional manner, while investing in automation and machine learning** to increase the efficiency with which defects are identified.

- Currently, the Company performs cycle-based inspections on its Electric System through manual processes that require employees to physically walk or drive the system to perform a visual inspection, take photos, and manually document and classify their findings.
- Through investments in automation and machine learning, the Company can achieve Full System Inspection, including 360-degree views of assets created through automated image collection by various methods (drone, helicopter, robotics, video cameras, etc.) and trained machine learning models that identify and analyze assets to target reliability improvements.

For example, as mentioned above in the HVD Lines section, the Company is using artificial intelligence software and machine learning to automate the review of video from the annual helicopter inspection to identify specific locations of vintage insulators, which are the largest contributor to customer outage minutes on the HVD system on average over the last 5 years.

In 2025, the Company will create a single repository for images to be leveraged for forestry, asset & defect identification, and wildfire use cases. The Company will also purchase four autonomous drones and work to secure an FAA line of sight restriction waiver so that the drones will be able to complete autonomous missions within a defined five-mile radius.

Maintaining Digital Assets

Equally as important as investments in new digital capabilities is the ability to properly maintain technology assets after implementation—including the underlying foundational infrastructure, systems and platforms in the Company's digital landscape.

Prudent technology asset management and replacement programs, system monitoring, timely upgrades, and continuous system patching to mitigate cyber threats are required to sustain stability, support, and security of existing systems that directly and indirectly drive electric reliability.

Technology and Analytics Investment Plan

The plan for Next Digital Investments will cost $14 million over the next three years.

See Figure 125 below for the Next Digital Investments plan.

Figure 125
NEXT DIGITAL 3-YEAR INVESTMENT PLAN



Economic Development and "Mega-sites"

In June 2023, EPRI published a prospectus *The Impact of Industrial Onshoring on Electric Sector Demand Growth*, assessing the impacts of industrial onshoring and more recently the increase in data centers across the nation, both representing opportunities for the Company and State of Michigan to partner to win major industrial projects and boost the state's economy.

Business sectors and individual organizations continue to factor supply chain risks into strategic positioning and operational decision-making. Similarly, the U.S. government has been investing unprecedented sums in domestic manufacturing, infrastructure, and decarbonization to improve national security and create jobs.

In 2024, the Site Selectors Guild, in partnership with Development Counsellors International, published their *State of Site Selection* report and highlighted that these U.S. programs have resulted in construction spending on new manufacturing facilities, more than doubling from 2022 to 2023 in such industries as data centers, electric vehicles, battery plants, and semiconductors.

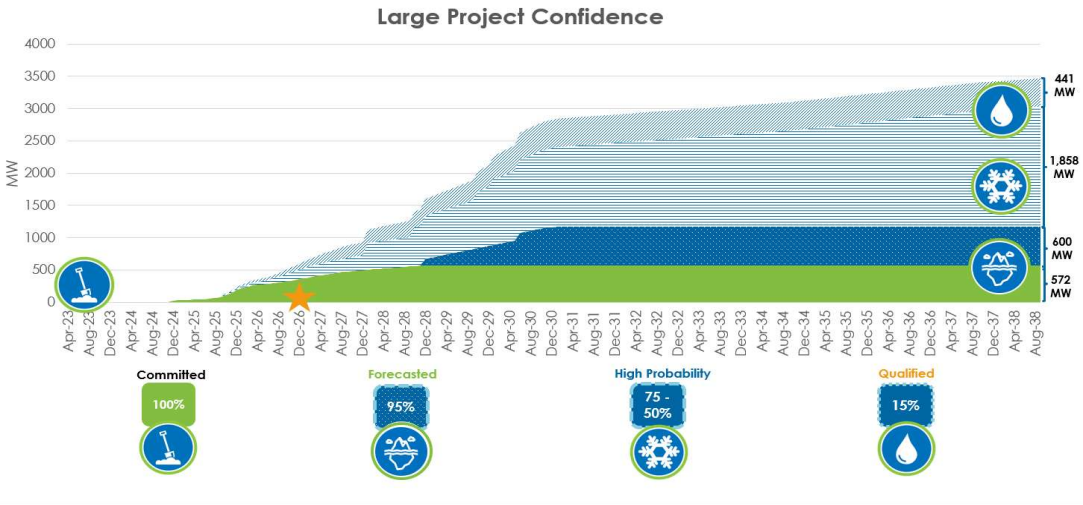
These events have created new conditions and opportunities for states to coordinate with utilities to address the complex needs associated with securing these projects. In the *State of Site Selection,* **electric power capacity is rated a 4.7 out of 5 point scale of having a significant impact on industrial project location decisions**. Of site consultants surveyed, 98% were in agreement that electric power capacity will significantly impact the future of industrial projects.

New manufacturing plants can generate significant local impact by adding large blocks of load. Serving new demand creates the need for new approaches to load as well as coordinated planning and development of grid infrastructure. This is because the demand growth created by industrial onshoring can have disruptive impact at local levels.

Figure 126 below shows the load projected to be added to the system as part of large projects greater than 35 megawatts ("MW").

Figure 126

ECONOMIC DEVELOPMENT LARGE PROJECT MW PROJECTIONS



Industrial reshoring continues to create demand growth in the Company's service territory, which is poised to play an outsized role in the EV battery industry, due to its proximity to existing American auto manufacturing plants.

Data centers also represent a growing sector across the nation, with many areas already seeing an unprecedented number of requests for large amounts of demand.

Currently, the Company has over 40 leads and opportunities, totaling more than 14,800 MW of potential load related to data centers alone. This potential load is not represented in the graph above. In the *State of Site Selection* report it was quoted from the Boston Consulting Group that data center electricity consumption was 2.5 percent of the U.S. total in 2022, and is expected to triple by 2030.

- To win these major projects, **increased coordination among the Company as well as manufacturers, system operators, development agencies, regulators, and other stakeholders is essential** to ensuring significant new demand can be met efficiently and in a timely fashion.

Workplan

The Company regularly works with the *Michigan Economic Development Corporation* ("MEDC") and other local economic development groups competing for prospective new large industrial customer facilities that are considering establishing a site in Michigan.

- We provide competitive electric service proposals as part of a broader Michigan response to RFPs.
- Many of these RFPs are very competitive in nature, and consider sites across North America, including considering if a site is ready and able to meet customer project timelines.

These RFP response efforts benefit the broader economy of the state of Michigan when a Michigan site is selected as the final location.

Large new customer connections and load additions provide the benefits of job creation, plus other state and local government revenue streams associated with business expansion.

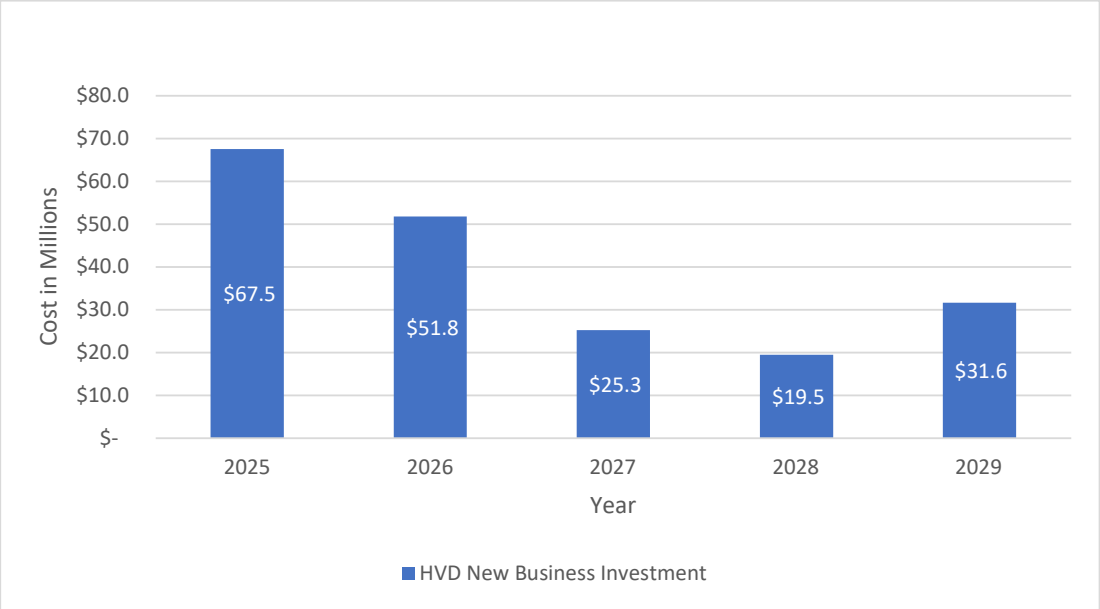
However, the Company has learned that the lead time to install a large, new dedicated customer substation and the associated lines are often prohibitive for potential customers, who are looking for "shovel-ready" sites where they can start production as soon as possible.

- The Company is pursuing a solution for such a situation in advance by standardizing our design and equipment and pre-purchasing long lead-time equipment.
- This will reduce the time needed to provide electric solutions for potential customers, and create an advantageous position to attract large, transformational, and new business opportunities to the state of Michigan.

Figure 127 below represents the planned investment needed to support known and planned projects and potential projects that are known but not yet committed.

Figure 127

NEW BUSINESS PLANNED INVESTMENT



Hosting Capacity Analysis

Hosting capacity **is defined as "the amount of distributed energy resources ("DERs") that can be accommodated without adversely impacting operational criteria**, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades."[14]

The Company interconnects DERs to its distribution system through an MPSC-regulated interconnection process. When a proposed DER goes through this process, the Company performs a resource-specific analysis to ensure that the resource will not cause any reliability or capacity issues, and to identify any necessary system upgrades. The analysis can range significantly in complexity based on the size of the proposed DER.

A *hosting capacity analysis* ("HCA") can improve and streamline this process by identifying locations on the system with a high probability of accommodating DERs. While resource-specific analyses are still required with an HCA, an HCA can help customers and DER developers avoid proposing interconnections and incurring study costs in areas that are not suitable for DERs.

In 2020, the MPSC directed the Company to pursue a 'phased' approach to developing HCAs, with two primary phases:

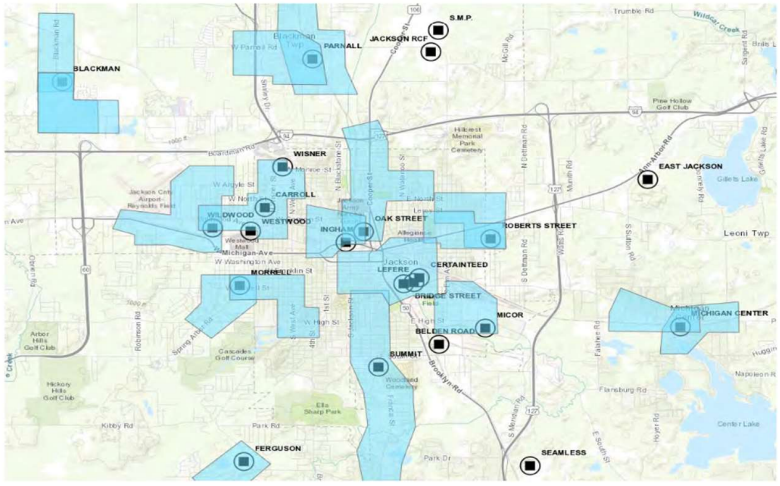
Phase I: A base-level approach with a zonal go/no-go map

Phase II: Specific, detailed analyses on areas of the distribution system with high DER penetration, incorporating this information into a more detailed map with circuit voltage-level information as DER penetration continues to increase.

The Company completed the Phase I analysis and reported the initial results in its 2021 EDIIP filing, with a detailed description of Phase I methodology. Since that time, the Company has updated its Phase I analysis as system conditions have changed, and the Company maintains a publicly available updated version on its website:
https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d

Phase I hosting capacity analysis shows circuits, in polygon form, that have at least 2 MW of hosting capacity, and result in maps such as this:

Figure 128
EXAMPLE OF PHASE I HCA MAP



[14] August 20, 2020 Order in Case No. U-20147

The Company's 2021 EDIIP also committed the Company to move ahead with a Phase II analysis.

To date, the Company has still not seen areas of high DER penetration on its system that would trigger the specific, detailed circuit analysis as originally contemplated when the 2021 EDIIP was filed. However, the Company expects to have a Phase II analysis available by the second half of 2025.

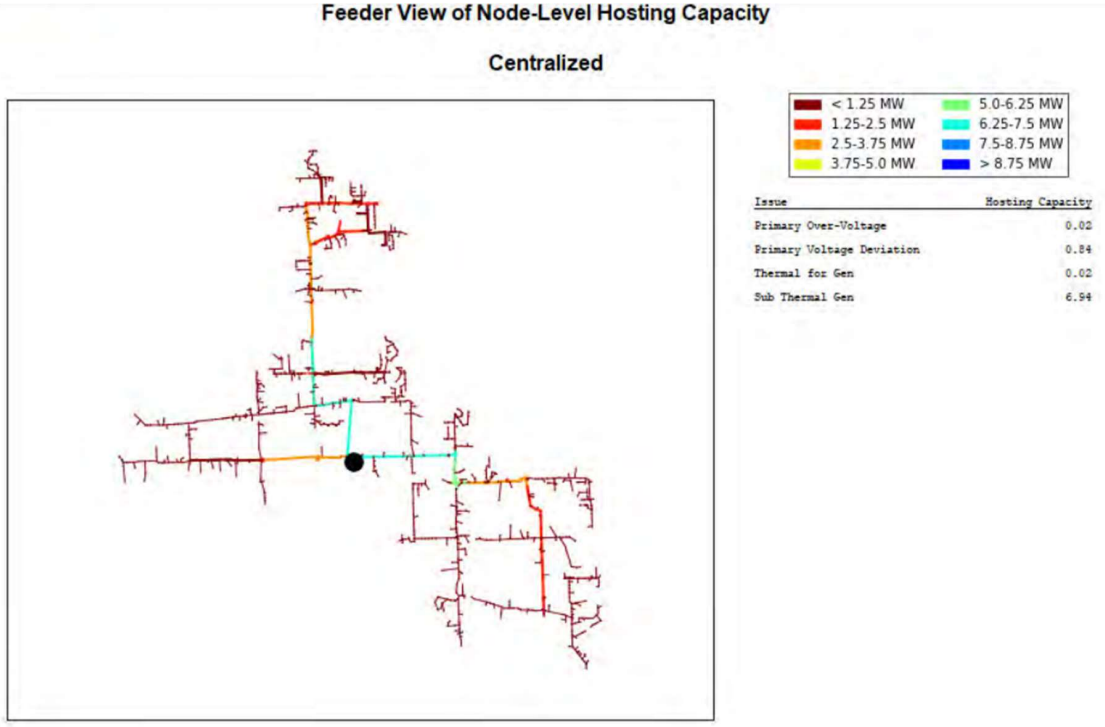
For its Phase II analysis, the Company will be able to use maximum load data from 2024 to create a snapshot of detailed hosting capacity information. This analysis relies on the Distribution Resource Integration and Value Estimation ("DRIVE") tool developed by EPRI, and also on the Company's CYME planning models.

Because manual analysis is still required with current capabilities, Phase II maps will be detailed but will not be updated in real time.

Phase II hosting capacity maps will show much more detailed circuit information, as follows:

Figure 129

ILLUSTRATIVE PHASE II HCA MAP – CIRCUIT LEVEL DETAIL



Going beyond periodic updates to Phase II maps will require the Company to complete the Load Flow Tool Upgrade proposed in its Grid Automation plan.

- The Load Flow Tool Upgrade will bring increased automation to the Company's CYME software, and will explore the use of EPRI DRIVE or CYME's Integrative Capacity Analysis module (ICA) for future hosting capacity analyses.
- The Load Flow Tool Upgrade will introduce time-series simulation capabilities in CYME, and will automate the modeling of existing and queued generation and load in the CYME network model. **This would enable a Phase III** of hosting capacity analysis, with much closer to real-time updates of the available maps.

Resources

Workforce

Field resources are an essential component for the successful continued investment into the electric distribution system. Resources both internal to the Company and externally contracted are staffed to match the work demand.

- The Company uses a **long-range resource planning process** to build workforce plans through a cross-functional planning methodology and deliver an optimally sized workforce that meets the Company's long-term needs.
- **This process reviews and aligns with a one-to-five-year resource plan**, factoring in demand, resource requirements, and resource availability to bring visibility to gaps and develop actions and scenarios to close them.
- The team leading the process **engages with Executive Leadership quarterly** to adjust resource plans and ensure resource adequacy.

This collaborative resource planning process works across the Electric Distribution organization to make informed decisions about the Company's electric field resources. The multi-year view ensures resource decisions are made with sufficient lead time to recruit, hire, and prepare Company field resources and external workforces for the work required.

The Company's field resource growth over the last five years has been deliberate to match the forecasted work demand and resource requirements for future years identified through the resource planning process.

This growth was due primarily to acquiring LVD field resources through apprenticeship hiring. These resources have been complemented during peak work demand months with a contractor workforce and have successfully met the work demand within each year.

Historical actuals below only include Company field resources over the last 5 years. This does not represent the entire workforce that was needed to deliver the work.

Figure 130

ELECTRIC DISTRIBUTION OPERATIONS: HISTORIC FIELD RESOURCE LEVELS (CE)

	2018	2019	2020	2021	2022	2023	2024
Year End Internal Resources	942	1,019	1,034	1,164	1,235	1,326	1,325

Ensuring Resource Adequacy

Using the resource planning process in collaboration with Electric Operations leadership, the upcoming multi-year resource forecast is available for field resources.

Figure 131 indicates the total resources required to meet our ambitious electric distribution investment strategy for 2025 through 2029.

Figure 132

Resources Required

	2025	2026	2027	2028	2029
LVD (including Underground)	1,160	1,547	1,589	1,969	2,000
HVD	496	538	542	494	492
Total Resources	1,656	2,085	2,131	2,463	2,492
Growth Percentage (YOY)		**26%**	**2.2%**	**15.6%**	**1.2%**

The previous 5 years incorporated resource growth with the Company's LVD workforce to meet identified work demand; however, implementing the *Resilient Grid Plan* will require that workforce growth accelerates more rapidly to meet the immediate resiliency investment needs of the grid.

- The increase in resources needed includes efficiency gains and increased productivity through leveraging predictive analytics, job-site reporting, and recruitment of qualified journey line workers.
- The Company supports its widespread LVD overhead system with a small workforce for its extensive mileage and coverage across the state of Michigan. This is executed with an efficient workforce and operations.

Even with this demonstrated efficiency, the scale of work outlined in this plan requires an even more aggressive growth rate to adequately support the planned investments.

Projected resource growth is driven by three main factors:

1. **LVD overhead field resource growth** of apprentices or qualified line workers to support the necessary system investment, which will be balanced with external contractors across peak time periods.
2. **Underground workforce growth** to match the proposed conversion work.

Maintaining a consistent workforce size or planning for growth—both require a reliable pipeline of talent to balance or exceed forecasted attrition.

Therefore, to ensure a talent pipeline for a long-term sustainable workforce, the Company initiated partnerships with strategic community colleges starting in 2008 to host line worker pre-apprenticeship programs.

These programs embody the triple bottom line by providing skilled trade training opportunities to local communities and future employees, investing in communities and their prosperity, and bringing diverse talent to the forefront of leading the clean energy transition.

- The *School to Work* program is one partnership that is currently investing in communities such as Flint, Muskegon, Alpena, Lansing, Grand Rapids, and Jackson, where career opportunities are immensely impactful, and continues to reinvest in the state of Michigan.
- This purposeful effort has yielded great success, as 74% of the Company's apprentice line worker hires have come through its *School to Work* programs since 2014.

Figure 133 and Figure 134 showcase some of these students and their training experiences.

Figure 133

SCHOOL TO WORK STUDENTS: MOTT COMMUNITY COLLEGE (FLINT, MI) & ALPENA COMMUNITY COLLEGE (ALPENA, MI)





Figure 134

Line Worker Pre-Apprenticeship Training: Alpena Community College (Alpena, MI)





The growth requirements of the underground workforce will be met as the Company will promote opportunities to other field resource roles in the Company who would be well-suited for this growing workforce.

The external programs that recruit these entry level roles confirm prerequisite skills for successful energy careers and have an extensive nation-wide pipeline.

To meet the investment into the electric grid that customers need and require, the Company's workforce plans also integrate the following methods to adequately staff for the future work demand, which will balance staffing growth:

- Drive towards increased efficiency in work or optimized scheduling, such as packaging similar work on a common circuit or within a single outage.

- Build work plans with agility to use the right workforce at the right time for the right response, allowing work to be levelized across months or peaks to be supported by contractor workforces.
- Manage workforce plans to inform talent pipeline programs with adequate lead time for apprenticeship training and hiring.

Using these methods will ensure work demand and field resource needs are identified for a minimum of a 5-year forecast. The Company's past successful hiring practices instill confidence that all forecasted resource requirements will be met, and will deliver a diverse and hometown-focused workforce.

Fleet

The Company supports its electric and gas businesses with a fleet that includes over 7,300 owned, leased, and rented units across 36 locations.

These units include light duty vehicles (approximately 2,800 units), medium and heavy-duty trucks (approximately 1,500 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units).

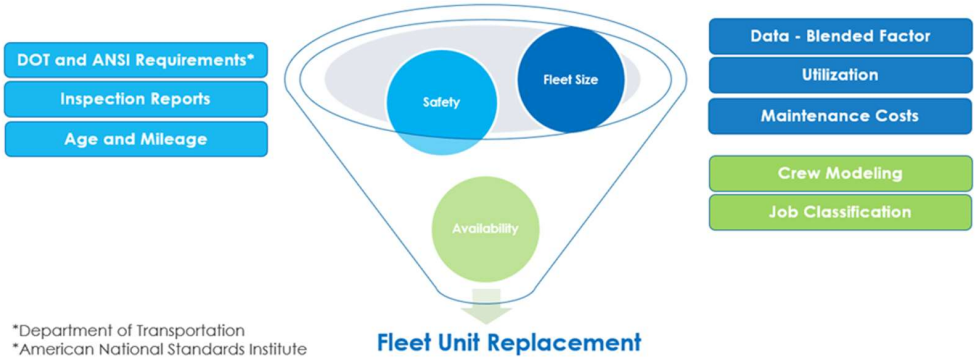
Vehicles are ordered and upfitted to support specific work and are, therefore, specialized for the work they perform; however, the Company does seek ways units can be shared across the business when possible. Some Company fleet units, such as pick-up trucks, vans and sedans support both electric and gas work.

Much of the Company's fleet strategy is focused on its *Fleet Vehicle Capital Replacement Plan*, based on a *Fleet Replacement Planning Process*. This replaces vehicles as they reach the end of their useful life, using a three-phase process:

1. Vehicles are identified as being at the end of life using a tool called the *Blended Factor*, described below in Figure 135.
2. Vehicles identified for potential replacement are further analyzed by considering fleet cost data, crewing data, and fleet utilization data; qualitative inputs like maintenance reports are also considered.
3. Vehicles are confirmed for retirement based on these evaluations, and ordering begins, either through existing contracts or by putting out requests for proposal.

Figure 135

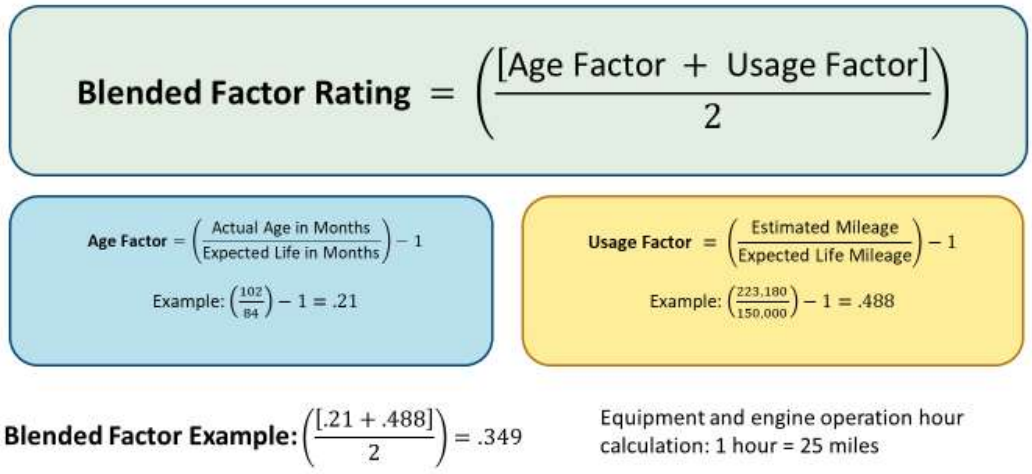
Fleet Capital Replacement Plan Filter



The Blended Factor calculation considers vehicle age, usage, and mileage to identify vehicles nearing end of life, as follows:

Figure 136

Blended Factor Calculation



The pool of vehicles identified by the Blended Factor analysis is narrowed by reviewing cost data to determine if it is more economical to continue maintaining a vehicle or to replace it.

- Crewing data helps determine how many vehicles the Company has relative to its workforce and that workforce's needs, ensuring that a replacement strategy continues to deliver the right number and types of vehicles.
- Fleet utilization data helps identify if any vehicles are not being fully used.

In addition to the Fleet Vehicle Capital Replacement Plan, the Company also expands its fleet as necessary to specifically support workforce expansion. As detailed in the prior Workforce section of this report, the Company's increased distribution investments require expansion of key parts of the workforce, which will in turn require an expanded fleet.

To support fleet expansion, the Company compares current fleet resources with projected crewing levels before expansion takes place, identifying any gaps indicated by the crewing model, and then develops a plan to procure vehicles needed to close those gaps, informed by qualitative inputs from the affected workforce areas with relevant knowledge about the work to be done.

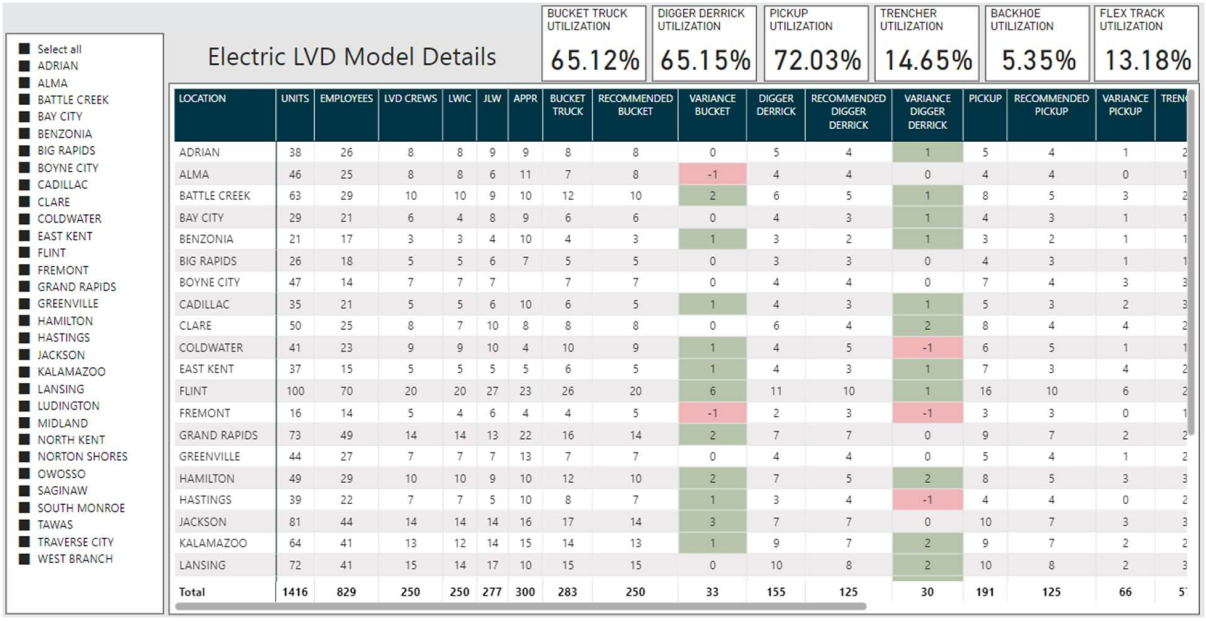
To address immediate needs, the Company has established contracts with multiple fleet unit vendors. These vendors can supply trucks and equipment as necessary to bridge potential gaps with relatively short notice.

As the Company develops the scope of various projects, a clearer understanding of the specific equipment and resources required are determined based on the workforce needed. This process helps in identifying gaps where additional or different equipment might be needed.

The Company has developed a Crewing Model that helps forecast where potential gaps exist to aid in determining proper equipment levels throughout the business. An illustrative example of the Crewing Model is shown below.

Figure 137

Electric Crewing Model



- Select all
- ADRIAN
- ALMA
- BATTLE CREEK
- BAY CITY
- BENZONIA
- BIG RAPIDS
- BOYNE CITY
- CADILLAC
- CLARE
- COLDWATER
- EAST KENT
- FLINT
- FREMONT
- GRAND RAPIDS
- GREENVILLE
- HAMILTON
- HASTINGS
- JACKSON
- KALAMAZOO
- LANSING
- LUDINGTON
- MIDLAND
- NORTH KENT
- NORTON SHORES
- OWOSSO
- SAGINAW
- SOUTH MONROE
- TAWAS
- TRAVERSE CITY
- WEST BRANCH

Electric LVD Model Details

BUCKET TRUCK UTILIZATION	DIGGER DERRICK UTILIZATION	PICKUP UTILIZATION	TRENCHER UTILIZATION	BACKHOE UTILIZATION	FLEX TRACK UTILIZATION
65.12%	65.15%	72.03%	14.65%	5.35%	13.18%

LOCATION	UNITS	EMPLOYEES	LVD CREWS	LWIC	JLW	APPR	BUCKET TRUCK	RECOMMENDED BUCKET	VARIANCE BUCKET	DIGGER DERRICK	RECOMMENDED DIGGER DERRICK	VARIANCE DIGGER DERRICK	PICKUP	RECOMMENDED PICKUP	VARIANCE PICKUP	TREN
ADRIAN	38	26	8	8	9	9	8	8	0	5	4	1	5	4	1	2
ALMA	46	25	8	8	6	11	7	8	-1	4	4	0	4	4	0	1
BATTLE CREEK	63	29	10	10	9	10	12	10	2	6	5	1	8	5	3	2
BAY CITY	29	21	6	4	8	9	6	6	0	4	3	1	4	3	1	1
BENZONIA	21	17	3	3	4	10	4	3	1	3	2	1	3	2	1	1
BIG RAPIDS	26	18	5	5	6	7	5	5	0	3	3	0	4	3	1	1
BOYNE CITY	47	14	7	7	7		7	7	0	4	4	0	7	4	3	3
CADILLAC	35	21	5	5	6	10	6	5	1	4	3	1	5	3	2	3
CLARE	50	25	8	7	10	8	8	8	0	6	4	2	8	4	4	2
COLDWATER	41	23	9	9	10	4	10	9	1	4	5	-1	6	5	1	1
EAST KENT	37	15	5	5	5	5	6	5	1	4	3	1	7	3	4	2
FLINT	100	70	20	20	27	23	26	20	6	11	10	1	16	10	6	2
FREMONT	16	14	5	4	6	4	4	5	-1	2	3	-1	3	3	0	1
GRAND RAPIDS	73	49	14	14	13	22	16	14	2	7	7	0	9	7	2	2
GREENVILLE	44	27	7	7	7	13	7	7	0	4	4	0	5	4	1	2
HAMILTON	49	29	10	10	9	10	12	10	2	7	5	2	8	5	3	3
HASTINGS	39	22	7	7	5	10	8	7	1	3	4	-1	4	4	0	2
JACKSON	81	44	14	14	14	16	17	14	3	7	7	0	10	7	3	3
KALAMAZOO	64	41	13	12	14	15	14	13	1	9	7	2	9	7	2	2
LANSING	72	41	15	14	17	10	15	15	0	10	8	2	10	8	2	3
Total	1416	829	250	250	277	300	283	250	33	155	125	30	191	125	66	5

Conclusion and Financial Summary

The Company is modernizing its electric distribution system to safely deliver clean, affordable, reliable power to customers throughout Michigan. **The goal is simple: fewer and shorter power outages for customers.** The vision for the grid is a blueprint for serving Michigan today and innovating to meet the challenges of the coming decades.

The *Reliability Roadmap*, laying out the investment levels summarized in the chart below, charts a new course for the Company in terms of reliability, resiliency, and investment.

The Company has identified **severe weather and technological adoption as the most pressing challenges** to the future grid and modeled the circuit level impacts from these risks through 2050.

This plan will underpin the Company's strategy for distribution investment planning to mitigate the current risk of severe weather and storms, and will serve as a bridge from our current grid to a grid capable of achieving the following reliability objectives:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities.**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

The *Reliability Roadmap* will also **significantly improve the Company's SAIFI performance** over the next decade when compared to what would be provided by recent electric rate case-approved levels of investment.

Increased risks from weather and technological adoption will require a significant shift in investment levels and strategy to mitigate the risks from extreme weather and improve the reliability of electric power.

The *Reliability Roadmap* features a unique approach for each voltage system, and a detailed work plan for each asset type.

- The plan for the LVD system will mitigate the worst effects of extreme weather and begin proactive planning for an increasingly electrified future, while the plan for the HVD system will focus on maintaining recent progress through proactively inspecting all assets repairing components on the HVD system to keep them within their useful lifecycle.
- This plan will focus on assets to modernize and harden the Company's electric distribution system to safely provide power with fewer, shorter, and less frequent power outages for customers through the Five Fundamentals Framework: **Fix, Fuse, Fractionalize, Fortify** and **Forestry**.

To execute on this vision, the plan proposes to invest over the next 5 years in the following areas:

FIGURE 138

INVESTMENT PLAN (2025-2029)

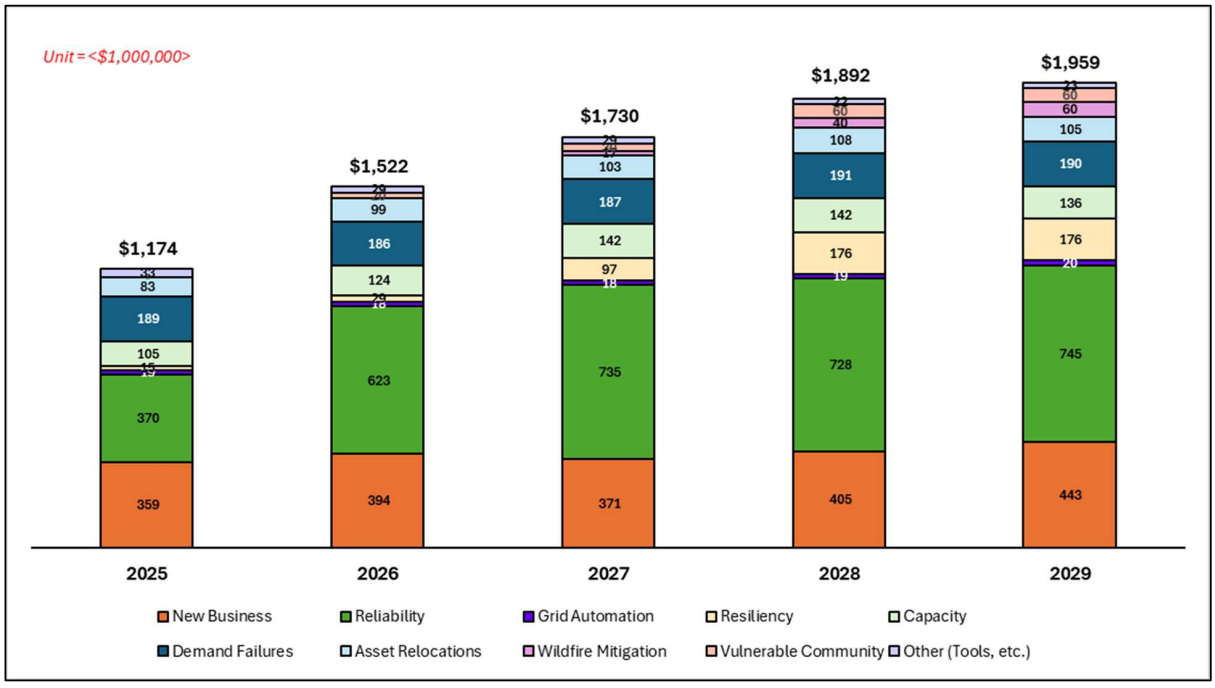
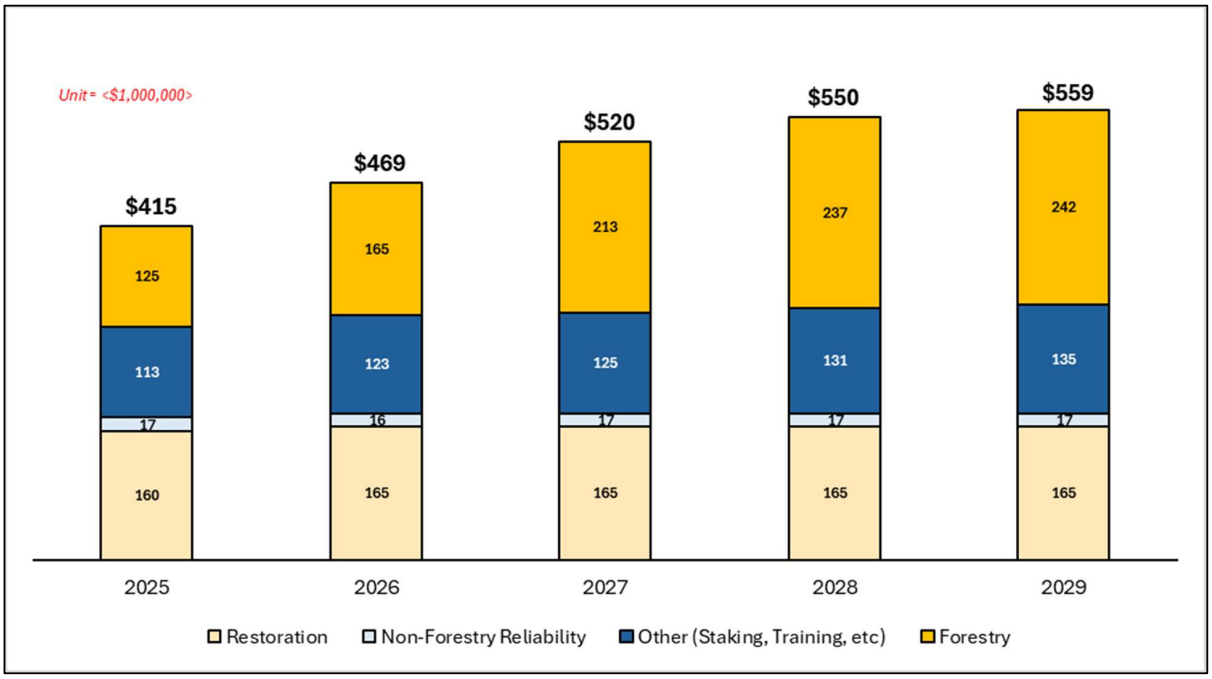


FIGURE 139
O&M PLAN (2025-2029)



This plan also incorporates Environmental Justice into its planning for capital projects and maintenance to ensure disadvantaged communities receive reliable power.

- The Forestry Line Clearing work included in this plan is essential to **addressing the largest single risk to reliability on LVD system** and the Company has developed a prescriptive line clearing impact analysis, with a focus on reliability metrics and tree-caused incidents to inform this work.
- The Company is **expanding its use of data-driven strategies** to guide its LVD full circuit clearing and ramp up to a 5-year clearing cycle for all distribution lines.
- Technology, Analytics, and Grid Modernization will complement the asset investments through developing **new tools and systems to improve the way the Company monitors, controls, and optimizes assets.** Digital will serve as the accelerant to achieve our reliability aspirations by leveraging artificial intelligence, machine learning, and automation to optimize processes, identify trends, and improve customer experiences.

The work described in this Plan relies on adequate field resources, both internal to the Company and externally contracted, to match the work demand.

Our unionized workforce is an essential component for the successful continued investment into the electric distribution system. The Company has seen continued field resource growth over the last 5 years, and has been deliberate in matching the forecasted work demand.

This plan will accelerate this growth into the future with a combination of new resiliency investment and increased maintenance of our system.

As described earlier in the Highlights of the Reliability Roadmap section, the Company fundamentally believes that the **investments outlined in this plan will deliver the safety, reliability, and resiliency benefits** that customers expect. The Company plans to seek recovery for these investments. Timely recovery of the costs of the investments described in this plan is essential to delivering the desired improvements in performance.

The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is executed and further improved over time.

The Company plans to file updates to this plan, adding future years of investment and accounting for additional years of actual spending, with each subsequent rate case filing as an exhibit supporting test year investments.

Appendix A – Grid Archetype Details and Supporting Figures

Figure 140

CIRCUIT CHARACTERISTICS FOR ARCHETYPE CLASSIFICATION - EXAMPLE

	LVD Archetypes							
LVD Focused Statistics	#1	#2	#3	#4	#5	#6	#7	TOTAL
SUMMARY STATISTICS								
# of Circuits	248	233	257	492	341	213	259	**2,043**
% of Total	*12%*	*11%*	*13%*	*24%*	*17%*	*10%*	*13%*	***100%***
CUSTOMER								
# of Customers	11,844	152,356	161,670	763,240	257,832	165,754	327,777	**1,840,473**
% of Total Customers	*1%*	*8%*	*9%*	*41%*	*14%*	*9%*	*18%*	***100%***
Average # of Customers/ Circuit	48	654	629	1551	756	778	1266	**901**
Residential Net Promoter Score (CMS Nov. Survey; Sum of respondents)	-	15%	21%	20%	12%	10%	10%	**15%**
Promoters	-	26	53	221	70	71	111	**552**
Neutrals	-	18	31	123	47	30	66	**315**
Detractors	-	17	29	127	50	56	85	**364**
# of Critical Customers (e.g., Hospital, Police, Telephone etc.)	69	188	120	276	125	40	103	**921**
% of Total Critical Customers	*7%*	*20%*	*13%*	*30%*	*14%*	*4%*	*11%*	***100%***
% of Circuits serving one or more Critical Customer	*23%*	*42%*	*25%*	*31%*	*25%*	*12%*	*27%*	***0***
# of Priority Customers (e.g., Major customers, Business centers)	446	1,053	806	1,848	919	445	725	**6,242**
% of Total Priority Customers	*7%*	*17%*	*13%*	*30%*	*15%*	*7%*	*12%*	***100%***
% of Circuits serving one or more Priority Customer	*65%*	*90%*	*83%*	*91%*	*71%*	*65%*	*75%*	***79%***
OPERATIONS								
Total Line Miles	577	3,348	2,390	11,134	15,281	10,149	17,467	**60,348**
Median Line Miles/ Circuit	1	12	9	20	42	48	60	**18**
Average Line Miles/ Circuit	2	14	9	23	45	48	67	**29**
Standard Deviation of Line Miles/ Circuit	4	10	5	13	22	20	35	**28**
Overhead Miles	289	2,387	1,556	7,622	14,138	9,249	15,693	**50,934**
Overhead Miles % of Total	*50%*	*71%*	*65%*	*68%*	*93%*	*91%*	*90%*	***84%***
Underground Miles	289	961	835	3,513	1,142	900	1,775	**9,414**
Underground Miles % of Total	*50%*	*29%*	*35%*	*32%*	*7%*	*9%*	*10%*	***16%***
Median Customers/ Line Mile	15	47	69	71	19	16	19	**31**

Figure 141

CALCULATIONS OF LVD ARCHETYPE ENVELOPE GUARDRAILS – ILLUSTRATIVE EXAMPLE

LVD Planned Capital Projects (Excludes forestry)
All spend values are loaded

Year	Illustrative
Total LVD Budget Allocation	$225M
Envelope Percent Change	20%

		LVD						
Archetype Metrics	**TOTAL**	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**
# of Circuits (LVD)	***2,163***	*422*	*224*	*260*	*476*	*337*	*258*	*186*
Spend/ Circuit (LVD)	**$104,022**	$43.9M	$23.3M	$27.0M	$49.5M	$35.1M	$26.8M	$19.3M
# of Customers (LVD Circuits)	**1,782,404**	*15,334*	*157,564*	*178,952*	*712,991*	*274,157*	*201,343*	*242,063*
Spend/ Customer (LVD)	**$126**	$1.9M	$19.9M	$22.6M	$90.0M	$34.6M	$25.4M	$30.6M
Total Line Miles (LVD)	**58,190**	*528*	*3,245*	*2,666*	*11,221*	*14,775*	*12,749*	*13,006*
Spend/ Line Mile (LVD)	**$3,867**	$2.0M	$12.5M	$10.3M	$43.4M	$57.1M	$49.3M	$50.3M
Yearly SAIDI Contribution (Excl. MED; Excluding HVD, '15-19)	***153***	*0.72*	*12.29*	*6.79*	*38.23*	*23.65*	*27.00*	*44.67*
Spend/ Minute of SAIDI Contribution	**$1,467,333**	$1.1M	$18.0M	$10.0M	$56.1M	$34.7M	$39.6M	$65.5M
Yearly SAIFI Contribution (Excl. MED; Excluding HVD, '15-19)	**0.76**	*0.00*	*0.07*	*0.04*	*0.22*	*0.12*	*0.13*	*0.19*
Spend/ Frequency Contribution	**$294M**	$1.1M	$19.5M	$11.1M	$63.7M	$34.4M	$38.6M	$56.6M
Guardrail Analysis								
Median Allocated Spend per Archetype	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
Median spend as a % of Total	***100%***	*0.9%*	*9.2%*	*5.3%*	*26.4%*	*16.3%*	*18.2%*	*23.7%*
Low Budget Spend Envelope (-20%)	**$180M**	$1.6M	$16.6M	$9.5M	$47.6M	$29.4M	$32.7M	$42.6M
Medium Budget Spend Envelope (Base)	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
High Budget Spend Envelope (+20%)	**$270M**	$2.5M	$24.8M	$14.2M	$71.3M	$44.1M	$49.1M	$64.0M

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

2020-2024 Distribution Unit Costs

Case No.: U-21870
Exhibit No.: A-130 (MPK-20)
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Date: June 2025

Line No.	Program / Investment Category	2020 (a) Capital	2020 (b) Projects	2020 (c) Unit Cost	2021 (d) Capital	2021 (e) Projects	2021 (f) Unit Cost	2022 (g) Capital	2022 (h) Projects	2022 (i) Unit Cost	2023 (j) Capital	2023 (k) Projects	2023 (l) Unit Cost	2024 (m) Capital	2024 (n) Projects	2024 (o) Unit Cost
1	**Lines New Business - LVD**	**$ 86,752,115**	**9,188**		**$ 111,920,506**	**10,652**		**$ 128,886,338**	**9,662**		**$ 136,184,733**	**9,980**		**$ 116,118,244**	**9,040**	
2	New Services	$ 86,752,115	9,188	$ 9,442	$ 111,920,506	10,652	$ 10,507	$ 128,886,338	9,662	$ 13,340	$ 136,184,733	9,980	$ 13,646	$ 116,118,244	9,040	$ 12,971
3	**Lines Strategic Customers - HVD**	**$ 4,037,848**	**12**		**$ 20,268,195**	**7**		**$ 4,279,998**	**2**		**$ 11,070,690**	**6**		**$ 57,836,000**	**7**	
4	Investment Category	$ 4,037,848	12	$ 336,487	$ 20,268,195	7	$ 2,895,456	$ 4,279,998	2	$ 2,139,999	$ 11,070,690	6	$ 1,845,115	$ 57,836,000	7	$ 8,262,286
5	**Metro New Business**	**$ 4,562,009**	**34**		**$ 2,430,593**	**23**		**$ 1,856,029**	**43**		**$ 1,588,725**	**41**		**$ 11,187,596**	**34**	
6	Projects	$ 4,562,009	34	$ 134,177	$ 2,430,593	23	$ 105,678	$ 1,856,029	43	$ 43,163	$ 1,588,725	41	$ 38,749	$ 11,187,596	34	$ 329,047
7	**Transformers - LVD**	**$ 28,857,324**	**13,364**		**$ 37,927,064**	**10,433**		**$ 49,208,671**	**12,496**		**$ 64,137,462**	**15,047**		**$ 122,886,409**	**18,954**	
8	Transformers	$ 28,857,324	13,364	$ 2,159	$ 37,927,064	10,433	$ 3,635	$ 49,208,671	12,496	$ 3,938	$ 64,137,462	15,047	$ 4,262	122,886,409	18,954	$ 6,483
	New Business															
9	**Lines Reliability - LVD**	**$ 33,257,402**	**1,222**		**$ 39,451,348**	**1,293**		**$ 50,631,252**	**10,745**		**$ 34,935,151**	**7,949**		**$ 25,824,724**	**751**	
10	Targeted Circuit Improvements (projects)	$ 20,721,283	191	$ 108,488	$ 23,427,418	209	$ 112,093	$ 42,034,097	10,546	$ 3,986	$ 27,278,225	7,798	$ 3,498	$ 17,763,268.00	503	$ 35,315
11	Pole Replacements (poles)	$ 8,490,227	1,016	$ 8,357	$ 10,599,623	1,055	$ 10,047	$ 2,534,948	172	$ 14,738	$ 1,894,863	137	$ 13,831	$ 1,330,180.00	231	$ 5,758
12	Circuit Exit Enhancements (projects)	$ 505,437	15	$ 33,696	$ 1,266,069	29	$ 43,658	$ 1,403,810	27	$ 51,993	$ 655,794	14	$ 46,842	$ 529,504.00	17	$ 31,147
13	ROW Easements	$ 3,540,456	N/A		$ 4,158,238	N/A		$ 4,658,397	N/A		$ 5,106,269	N/A		$ 6,201,772.00	N/A	
14	**Lines Reliability - HVD**	**$ 22,289,686**	**491**		**$ 58,092,338**	**570**		**$ 42,565,119**	**715**		**$ 21,703,195**	**254**		**$ 32,263,573**	**552**	
15	Line rebuilds (miles)	$ 8,251,822	23	$ 358,775	$ 32,946,529	32	$ 1,029,579	$ 18,219,292	40	$ 455,482	$ 15,077,709	9	$ 1,675,301	$ 8,976,122	12	$ 748,010
16	Pole top rehabilitations (miles)	$ 3,960,563	46	$ 86,099	$ 13,583,527	110	$ 123,487	$ 7,195,963	95	$ 75,747	$ 504,706	7	$ 72,101	$ 5,583,078	49	$ 113,940
17	Pole replacements (poles)	$ 8,012,838	389	$ 20,599	$ 9,739,363	402	$ 24,227	$ 15,152,831	545	$ 27,803	$ 6,011,798	234	$ 25,691	$ 16,201,485	488	$ 33,200
18	Switches (incl. SCADA additions) (locations)	$ 2,064,464	33	$ 62,560	$ 1,822,919	26	$ 70,112	$ 1,997,034	35	$ 57,058	$ 108,982	4	$ 27,245	$ 607,027	3	$ 202,342
19	ROW Easements													$ 895,861		
20	**Substations Reliability - LVD**	**$ 12,583,299**	**38**		**$ 19,017,331**	**85**		**$ 16,884,427**	**72**		**$ 14,708,696**	**16**		**$ 17,573,928**	**48**	
21	New or rebuilt substations	$ 4,680,033	4	$ 1,170,008	$ 1,124,659	2	$ 562,330	$ 4,628,403	4	$ 1,157,101	$ 6,067,843	3	$ 2,022,614	$ 9,317,237	7	$ 1,331,034
22	Mobile substations	$ 4,333,957	3	$ 1,444,652	$ 4,745,155	1	$ 4,745,155	$ 3,333,542	1	$ 3,333,542	$ 2,250,653	2	$ 1,125,327	$ 25,620	-	$ -
23	Animal mitigation	$ 2,327,943	19	$ 122,523	$ 4,655,023	50	$ 93,100	$ 4,701,094	31	$ 151,648	$ 1,026,099	6	$ 171,017	$ 2,219,122	18	$ 123,285
24	Regulator replacements	$ 43,434	1	$ 43,434	$ 879,762	15	$ 58,651	$ 728,105	31	$ 23,487	$ 5,481	-	$ -	$ 715,226	14	$ 51,088
25	Transformer replacements	$ 108,389	-		$ 5,115,612	7	$ 730,802	$ 3,287,007	3	$ 1,095,669	$ 5,245,914	3	$ 1,748,638	$ 3,894,229	3	$ 1,298,076
26	Other Projects and Charges	$ 1,089,542	11	$ 99,049	$ 2,497,118	10	$ 249,712	$ 206,276	2	$ 103,138	$ 112,705	2	$ 56,353	$ 1,402,494	6	$ 233,749
27	**Substations Reliability - HVD**	**$ 5,100,000**	**61**		**$ 3,455,799**	**59**		**$ 3,992,844**	**62**		**$ 3,261,649**	**42**		**$ 5,715,476**	**55**	
28	Circuit breaker/switcher replacements	$ 3,673,000	27	$ 136,037	$ 2,216,790	19	$ 116,673	$ 1,470,249	14	$ 105,018	$ 2,678,521	17	$ 157,560	$ 2,659,728	20	$ 132,986
29	Transformer bushing replacements	$ 550,000	7	$ 78,571	$ 539,983	5	$ 107,997	$ 472,881	4	$ 118,220	$ 38,952	N/A	N/A	$ 1,367,384	10	$ 136,738
30	Switch replacements	$ 257,000	10	$ 25,700	$ 567,972	12	$ 47,331	$ 909,232	22	$ 41,329	$ 211,344	5	$ 42,269	$ 1,083,967	10	$ 108,397
31	Other	$ 620,000	17	$ 36,471	$ 131,054	23	$ 5,698	$ 1,140,482	22	$ 51,840	$ 332,832	20	$ 16,642	$ 604,397	15	$ 40,293
32	**System Protection**	**$ 2,626,241**	**58**		**$ 2,620,098**	**13**		**$ 4,503,577**	**41**		**$ 4,386,998**	**36**		**$ 4,848,000**	**17**	
33	Total Relay Replacements	$ 2,626,241	58	$ 45,280	$ 2,620,098	13	$ 201,546	$ 4,503,577	41	$ 109,843	$ 4,386,998	36	$ 121,861	$ 4,848,000	17	$ 285,176
34	**Repetitive Outages - LVD**	**$ 4,349,846**	**251**		**$ 10,713,652**	**350**		**$ 9,253,597**	**346**		**$ 4,082,239**	**122**		**$ 4,491,324**	**215**	
35	Total Repetitive Outage Projects	$ 4,349,846	251	$ 17,330	$ 10,713,652	350	$ 30,610	$ 9,253,597	346	$ 26,744	$ 4,082,239	122	$ 33,461	$ 4,491,324	215	$ 20,890
36	**Metro Reliability**	**$ 3,515,708**	**7**		**$ 5,737,248**	**20**		**$ 4,124,833**	**37**		**$ 3,985,200**	**35**		**$ 6,689,896**	**22**	
37	Obsolete or Needed Civil Assets	$ 1,150,446	2	$ 575,223	$ 1,769,322	1	$ 1,769,322	$ 712,306	9	$ 79,145	$ 1,554,333	5	$ 310,867	$ 3,228,969	6	$ 538,161
38	Obsolete or Needed Electrical Assets	$ 2,247,443	5	$ 449,489	$ 2,085,336	14	$ 148,953	$ 1,559,203	16	$ 97,450	$ 624,775	15	$ 41,652	$ 684,703	8	$ 85,588
39	Dead Fronting Equipment	$ 55,427	-		$ 1,827,937	4	$ 456,984	$ 1,832,347	10	$ 183,235	$ 873,040	13	$ 67,157	$ 1,634,741	5	$ 326,948
40	New Technologies	$ 62,393	-		$ 54,653	1		$ 20,978	2	$ 10,489	$ 933,052	2	$ 466,526	$ 1,141,484	3	$ 380,495
41	**Grid Automation**	**$ 72,263,929**	**1,748**		**$ 74,153,885**	**2,343**		**$ 52,816,893**	**3,167**		**$ 29,037,543**	**2,575**		**$ 20,195,352**	**3,206**	
42	DSCADA & SCADA	$ 18,184,037	64	$ 284,126	$ 19,213,429	84	$ 228,731	$ 13,954,409	64	$ 218,038	$ 5,446,740	11	$ 495,158	$ 1,341	0	
43	ATR Loops	$ 12,579,111	22	$ 571,778	$ 16,707,963	25	$ 668,319	$ 15,868,980	36	$ 440,805	$ 11,110,673	24	$ 462,945	*shifted to LVD Lines Reliability - see Fig. 37 of witness Partlan's testimony		
44	Line Sensors	$ 7,096,826	1,100	$ 6,452	$ 8,085,793	1,719	$ 4,704	$ 3,518,698	2,342	$ 1,502	$ 5,969,833	2,379	$ 2,509	$ 10,831,582	2979	$ 3,636
45	Voltage Regulator Controllers	$ 5,095,218	210	$ 24,263	$ 6,358,823	162	$ 39,252	$ 5,654,047	367	$ 15,406	$ 3,143,732	160	$ 19,648	$ 3,501,251	156	$ 22,444
46	LVD Capacitor Upgrades & Replacements	$ 576,655	300	$ 1,922	$ 787,394	353	$ 2,231	$ 415,640	358	$ 1,161	$ 109,507	-		$ 291,425	71	4104.577465
47	Misc Sub & HVD Work	$ -			$ -			$ -								
48	Circuit West	$ 294			$ 32											
49	Cellular Communications Upgrades	$ 521														
50	Substation Modernization													$ 3,481	N/A	
51	Advanced Technology Projects	$ 21,518,012	-		$ 23,696,696	-		$ 13,934,001	-		$ 3,252,695	-		$ 5,524,312		
52	Substations Comm Upgrades	$ 7,213,255	52	$ 138,716	$ (696,245)	-		$ (528,883)	-		$ 4,364			$ 41,960	N/A	
53	**Lines and Subs Rehabilitation HVD (now Transformer Replacements & Sub Rebuilds)**	**$ 15,460,833**	**661**		**$ 29,896,106**	**779**		**$ 39,183,968**	**867**		**$ 28,395,172**	**634**		**$ 26,676,254**	**603**	
54	Pole replacements	$ 4,777,998	249	$ 19,189	$ 4,007,742	227	$ 17,655	$ 7,098,950	291	$ 24,395	$ 4,277,002	146	$ 29,295	$ 6,981,392	284	$ 24,582
55	Pole top assembly replacements	$ 3,020,281	373	$ 8,097	$ 5,597,280	541	$ 10,346	$ 5,579,111	563	$ 9,910	$ 4,061,358	482	$ 8,426	$ 3,056,556	301	$ 10,155
56	Switch (incl. MOAB) replacements	$ 760,267	15	$ 50,684	$ 552,306	4	$ 138,077	$ 958,270	10	$ 95,827	$ 273,642	5	$ 54,728	$ 1,422,525	17	$ 83,678
57	Miscellaneous other replacements	$ 63,772	24	$ 2,657	$ 46,576	7	$ 6,654	$ 186,377	3	$ 62,126	$ 181,203	1	$ 181,203	$ 24,695	1	$ 24,695
58	HVD substation replacement projects	$ 6,838,515			$ 19,692,203			$ 25,361,260			$ 19,601,967			$ 15,191,086		
59	**Substations Rehabilitation LVD**	**$ 9,838,498**	**17**		**$ 18,379,139**	**32**		**$ 10,941,033**	**20**		**$ 8,481,963**	**12**		**$ 13,860,340**	**11**	
60	Allis Chalmers transformer replacements	$ 6,541,995	6	$ 1,090,333	$ 12,464,595	15	$ 830,973	$ 6,408,239	5	$ 1,281,648	$ 4,499,628	4	$ 1,124,907	$ 6,018,840	3	$ 2,006,280
61	Equipment replacement and regulatory	$ 3,296,503	11	$ 299,682	$ 3,908,037	14	$ 279,146	$ 3,077,226	13	$ 236,710	$ 3,982,335	8	$ 497,792	$ 7,841,500	8	$ 980,187
62	Transformer at imminent risk of failure	$ -	-		$ 2,006,506	3	$ 668,835	$ 1,455,568	2	$ 727,784	$ -	-	$ -	$ -	-	$ -
63	**Lines Rehabilitation - LVD**	**$ 22,330,935**	**1,050**		**$ 33,547,774**	**809**		**$ 29,068,083**	**804**		**$ 12,529,815**	**584**		**$ 44,434,897**	**9,959**	
64	Security assessment repairs projects*	$ 14,423,542	220	$ 65,562	$ 23,684,410	267	$ 88,706	$ 19,095,171	188	$ 101,570	$ 7,641,659	180	$ 42,454	31,650,187	8,893	$ 3,559
65	Imminent rehabilitation	$ 7,907,393	830	$ 9,527	$ 9,863,364	542	$ 18,198	$ 9,972,912	616	$ 16,190	4,888,156	404	$ 12,099	$ 11,592,837.00	577	$ 20,092
66	Modern Replacement Program	-	-		$ -	-		$ -	-		$ -	-		$ 1,191,873.00	489	$ 2,437
67	**Metro Rehabilitation**	**$ 6,181,167**	**4**		**$ 3,163,241**	**7**		**$ 4,678,237**	**25**		**$ 7,033,641**	**25**		**$ 2,687,522**	**22**	
68	Crushed duct replacements	$ 162,092	1	$ 162,092	$ 2,545,721	5	$ 509,144	$ 1,562,800	5	$ 312,560	$ 2,704,924	7	$ 386,418	$ 513,480	6	$ 85,580
69	Vault or manhole rehabilitation	$ 6,019,075	3	$ 2,006,358	$ 617,520	2	$ 308,760	$ 3,115,436	20	$ 155,772	$ 4,328,718	18	$ 240,484	$ 2,070,385	11	$ 188,217
70	Imminent failure													$ 103,657	5	$ 20,731
	Grid Storage	**$ 2,551,649**	**3**		**$ 4,605,834**	**5**		**$ 646,667**	**4**							
71	Capacity Upgrade Deferral	$ 2,148,443	1	$ 2,148,443	$ 4,293,304	1	$ 4,293,304	$ 219,727	1	$ 219,727						
72	Islanded Battery	$ 127,460.00	1	$ 127,460	$ 161,717	1	$ 161,717	$ 357,301	1	$ 357,301						
73	Distribution Automation Battery				$ 1,389	1	$ 1,389	$ -	-							
74	DC-coupled Solar + Storage	$ 275,746	1	$ 275,746	$ 9,825	1	$ 9,825	$ -	-							
75	Fast Frequency Regulation Market participation				$ 139,988	1	$ 139,988	$ 6,110	1	$ 6,110						
76	Parkview Battery Main Controller Replacement							$ 63,529	1	$ 63,529						
77	**Reliability**															

***Security assessment repair now in LVD Lines Demand Failures - see testimony of witness Partlan**

MICHIGAN PUBLIC SERVICE COMMISSION
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2020-2024 Distribution Unit Costs

Case No.: U-21870
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Line No.	Program / Investment Category	2020 (a) Capital	2020 (b) Projects	2020 (c) Unit Cost	2021 (d) Capital	2021 (e) Projects	2021 (f) Unit Cost	2022 (g) Capital	2022 (h) Projects	2022 (i) Unit Cost	2023 (j) Capital	2023 (k) Projects	2023 (l) Unit Cost	2024 (m) Capital	2024 (n) Projects	2024 (o) Unit Cost
1	**Lines Capacity - LVD**	**$ 9,835,702**	**48**		**$ 8,216,776**	**42**		**$ 7,706,145**	**63**		**$ 2,926,592**	**45**		**$ 9,424,100**	**76**	
2	Overloaded equipment upgrades	$ 5,179,895	40	$ 129,497	$ 5,228,367	34	**$ 153,776**	$ 7,434,754	59	$ 126,013	$ 275,156	29	$ 9,488	$ 6,336,921	56	$ 113,159
3	Lines capacity projects assoc. w/ substation work	$ 4,655,806	8	$ 581,976	$ 2,988,409	8	**$ 373,551**	$ 271,391	4	$ 67,848	$ 2,651,436	16	$ 165,715	$ 3,087,179	20	$ 154,359
4	**Lines & Subs Capacity - HVD**	**$ 19,247,493**	**55**		**$ 17,365,080**	**53**		**$ 29,292,429**	**135**		**$ 25,805,134**	**89**		**$ 27,163,000**	**95**	
5	Load carrying capabilities and voltage support	$ 1,848,011	8	$ 231,001	$ 4,162,164	2	$ 2,081,082	$ 9,364,969	3	$ 3,121,656	$ 6,578,947	2	$ 3,289,473	$ 4,974,403	1	$ 4,974,403
6	New interconnections	$ 3,203,194	11	$ 291,199	$ 239,077	12	$ 19,923	$ 2,457,816	15	$ 163,854	$ 1,160,532	25	$ 46,421	$ (1,012,641)	11	$ (92,058)
7	Improved functionality	$ 3,749,722	16	$ 234,358	$ 4,230,554	16	$ 264,410	$ 9,761,576	91	$ 107,270	$ 8,899,117	16	$ 556,195	$ 13,775,703	43	$ 320,365
8	Coordination with Transmission	$ 5,722,701	9	$ 635,856	$ 3,983,908	17	$ 234,348	$ 2,733,013	4	$ 683,253	$ 2,016,771	5	$ 403,354	$ 8,786,917	5	$ 1,757,383
9	ROW procurement	$ 4,723,865	11	$ 429,442	$ 4,749,378	6	$ 791,563	$ 4,975,056	22	$ 226,139	$ 7,149,768	41	$ 174,385	$ 638,618	35	$ 18,246
10	**Substations Capacity - LVD**	**$ 10,685,958**	**61**		**$ 15,068,327**	**79**		**$ 12,766,649**	**73**		**$ 14,529,968**	**65**		**$ 25,886,601**	**20**	
11	New substations	$ 6,789,662	-	$ -	$ 8,974,225	5	$ 1,794,845	$ 4,186,031	3	$ 1,395,344	$ 7,436,504	-	$ -	$ 19,741,625	8	$ -
12	Existing substations capacity increase projects	$ 2,735,880	18	$ 151,993	$ 5,146,266	17	$ 302,722	$ 6,947,750	7	$ 992,536	$ 4,607,030	8	$ 575,879	$ 6,144,976	12	$ 512,081
13	Other Projects and Charges	$ 1,160,416	43	$ 26,986	$ 947,835	57	$ 16,629	$ 1,632,869	63		$ 2,486,433	57	$ 43,622	$ -	-	$ -
14	**New Business Cap - LVD**	**$ 17,766,617**	**1,257**		**$ 23,672,169**	**1,553**		**$ 27,187,902**	**1,544**		**$ 29,054,330**	**1,438**		**$ 33,429,196**	**1,294**	
15	Orders	$ 17,766,617	1,257	$ 14,134	$ 23,672,169	1,553	$ 15,243	$ 27,187,902	1,544	$ 17,609	$ 29,054,330	1,438	$ 20,205	33,429,196	1,294	$ 25,834
16	**Conservative Voltage Reduction CVR**	**$ 1,936,594**	**76**		**$ 7,191,371**	**204**		**$ 3,145,109**	**160**		**$ 1,310,828**	**38**		**$ 2,246,180**	**56**	
17	Construct Project	$ 1,936,594	76	$ 25,482	$ 7,191,371	204	$ 35,252	$ 3,145,109	160	$ 19,657	$ 1,310,828	38	$ 34,495	$ 2,246,180	56	$ 40,110
	Capacity															
18	**Lines Failures - LVD**	**$ 105,177,291**	**31,125**		**$ 123,508,957**	**29,986**		**$ 142,776,767**	**31,785**		**$ 159,370,587**	**31,508**		**$ 137,322,405**	**25,905**	
19	Service Restoration Orders	$ 105,177,291	31,125	$ 3,379	$ 123,508,957	29,986	$ 4,119	$ 142,776,767	31,785	$ 4,492	$ 159,370,587	31,508	$ 5,058	$ 137,322,405	25,905	$ 5,301
20	**Lines & Subs Failures - HVD**	**$ 6,782,000**	**156**		**$ 6,051,000**	**206**		**$ 10,015,000**	**256**		**$ 13,523,830**	**433**		**$ 11,705,270**	**299**	
21	Pole replacements	$ 2,017,000	69	$ 29,200	$ 1,618,000	86	$ 18,800	$ 2,515,000	76	$ 33,092	$ 2,955,115	97	$ 30,465	$ 4,434,237	97	$ 45,714
22	Pole top assembly replacements	$ 1,351,000	74	$ 18,200	$ 905,000	109	$ 8,300	$ 886,000	86	$ 10,302	$ 1,568,123	156	$ 10,052	$ 1,514,290	156	$ 9,707
23	Switch (incl. MOAB) replacements	$ 697,000	7	$ 99,500	$ 1,193,000	9	$ 132,600	$ 1,716,000	12	$ 143,000	$ 574,376	5	$ 114,875	$ 849,749	5	$ 169,950
24	Miscellaneous other replacements	$ 69,000	6	$ 11,500	$ 75,000	2	$ 37,300	$ 38,000	8	$ 4,750	$ 130,672	41	$ 3,187	$ 489,181	41	$ 11,931
25	HVD substation failure projects	$ 2,648,000	N/A		$ 2,260,000	N/A		$ 4,860,000	74	$ 65,676	$ 8,295,544	134	$ 61,907	$ 4,417,813		
26	**Substations Failures - LVD**	**$ 9,175,091**	**386**		**$ 12,781,598**	**298**		**$ 8,055,636**	**239**		**$ 14,868,807**	**216**		**$ 11,478,428**	**258**	
27	Allis Chalmers Substation Transformer Replacements	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -
28	Regulators	$ 2,401,031	72	$ 33,348	$ 2,793,635	86	$ 32,484	$ 2,294,466	67	$ 34,246	$ 3,043,913	52	$ 58,537	$ 5,289,888	88	$ 60,112
29	Reclosers	$ 914,337	63	$ 14,513	$ 867,933	53	$ 16,376	$ 999,513	58	$ 17,233	$ 824,022	34	$ 24,236	$ 1,686,206	50	$ 33,724
30	Transformers	$ 2,134,244	5	$ 426,849	$ 5,957,753	6	$ 992,959	$ 1,429,349	2	$ 714,674	$ 3,296,081	4	$ 824,020	$ 539,677	1	$ 539,677
31	End-of-Life Condition – Substation Rebuild	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -
32	Other Equipment and Charges	$ 3,725,479	246	$ 15,144	$ 3,162,277	153	$ 20,668	$ 3,332,308	112	$ 29,753	$ 7,704,792	126	$ 61,149	$ 3,962,656	119	$ 33,300
33	**Meters - LVD**	**$ 22,589,488**	**62,437**		**$ 22,368,078**	**205,706**		**$ 30,974,526**	**122,436**		**$ 58,653,212**	**148,820**		**$ 35,076,620**	**71,154**	
34	Meters, Transformers, & Sockets	$ 22,589,488	62,437	$ 362	$ 22,368,078	205,706	$ 109	$ 30,974,526	122,436	$ 253	$ 58,653,212	148,820	$ 394	$ 35,076,620	71,154	$ 493
35	**Metro Failures**	**$ 1,040,542**	**17**		**$ 50,156**	**11**		**$ 121,581**	**24**		**$ 463,641**	**22**		**$ 17,531**	**10**	
36	Projects	$ 1,040,542	17	$ 61,208	$ 50,156	11	$ 4,560	$ 121,581	24	$ 5,066	$ 463,641	22	$ 21,075	$ 17,531	10	$ 1,753
	Demand Failures															
37	**Lines Relocations - LVD**	**$ 32,961,000**	**3,525**		**$ 38,895,000**	**3,949**		**$ 52,814,000**	**3,727**		**$ 46,849,000**	**3,985**		**$ 51,502,458**	**4,582**	
38	Customer requested and other internal relocations	$ 23,527,000	2,557	$ 9,201	$ 27,202,000	2,856	$ 9,525	$ 27,091,000	2,257	$ 12,003	$ 26,696,000	2,131	$ 12,527	$ 25,443,532	2,718	$ 9,361
39	LVD underbuild relocations	$ 4,071,000	216	$ 18,847	$ 5,240,000	264	$ 19,848	$ 11,149,000	234	$ 47,645	$ 7,130,000	199	$ 35,829	$ 5,635,991	224	$ 25,161
40	Make-ready work	$ 5,363,000	752	$ 7,132	$ 6,453,000	829	$ 7,784	$ 14,574,000	1,236	$ 11,791	$ 13,023,000	1,655	$ 7,869	$ 20,422,935	1,640	$ 12,453
41	**Lines Relocations - HVD**	**$ 1,906,321**	**15**		**$ 1,709,173**	**17**		**$ 2,564,824**	**18**		**$ 5,319,332**	**36**		**$ 844,774**	**29**	
42	Projects	$ 1,906,321	15	$ 127,088	$ 1,709,173	17	$ 100,540	$ 2,564,824	18	$ 142,490	$ 5,319,332	36	$ 147,759	$ 844,774	29	$ 29,130
43	**Metro Relocations**	**$ 3,815,325**	**5**		**$ 6,549,541**	**16**		**$ 6,887,820**	**43**		**$ 5,160,711**	**47**		**$ 11,420,267**	**27**	
44	Projects	$ 3,815,325	5	$ 763,065	$ 6,549,541	16	$ 409,346	$ 6,887,820	43	$ 160,182	$ 5,160,711	47	$ 109,802	$ 11,420,267	27	$ 422,973
	Asset Relocations															
45	**Computer & Equipment**	**$ 2**			**$ 378**			**$ 6,272,688**			**$ 412,000**			**$ -**		
46	**Tools**	**$ 5,691,000**	**47**		**$ 11,114,404**	**374**		**$ 3,757,000**	**-**		**$ 5,537,898**			**$ 7,773,000**		
47	Truck tool packages	$ 2,736,000	47	$ 58,213	$ 5,885,000	169	$ 34,822	$ -	-		$ 977,898	16	$ 61,119	$ 727,000	24	$ 30,292
48	General capital tools	$ 2,955,000			$ 3,399,728			$ 2,557,000			$ 4,560,000			$ 7,046,000		
49	Reconductoring Equipment				$ 516,068	8		$ 125,000								
50	Employee fall restraint kits				$ 426,424	136		$ 420,000								
51	Substation bird mitigation equipment				$ 48,000	4		$ 70,000								
52	Tool crib/cabinet stock				$ 600,000	30		$ 225,000								
53	Infrared Cameras				$ 54,384	21		$ -								
54	Substation control house battery carts				$ 16,800	3		$ 35,000								
55	Breaker and HVD equipment testers				$ 168,000	3		$ 325,000								
56	**System Control Projects**	**$ 1,889,641**	**27**		**$ 1,193,499**	**107**		**$ 2,520,610**	**11**	$ 229,146	**$ 41,289**	**4**		**$ 896,025**	8	
57	HVD operations projects	$ 718,531	22	$ 32,661	$ 180,135	96	$ 1,876	$ 1,836,500	7	$ 262,357		-		$ -		
58	HVD Remote M&C Cap	$ -	-			-	$ -		-			-		$ -		
59	Operating technology enhancements	$ 250,000	2	$ 125,000	$ (23,803)	1	$ (23,803)	$ 192,510	2	$ 96,255		-		$ -		
60	Operations center modifications	$ 921,110	3	$ 307,037	$ 1,037,167	10	$ 103,717	$ 491,600	2	$ 245,800	$ 41,289	4	$ 10,322	$ 896,025	8	$ 112,003
61	Emergency Operations Center	$ 816,515	1	$ 816,515										$ -	0	

2023 Electric System Loss Study Report

Electric Distribution
June 20, 2024



Introduction

The purpose of this study is to allocate system energy and demand losses among the various components of the electric system by calculating a percentage Loss Factor for each system component. This information will be used to update loss calculations used in electric rate design. Electric Grid Models calculated Loss Factors for the 345, 138 and 46 kV systems and the low side of the 138 and 46 kV industrial systems. The Loss Factor for the Distribution Primary system was calculated from simulations on Primary LVD models. Finally, the Loss Factor for the Distribution Secondary system (including secondary transformers) was calculated from the amount of system loss remaining after all other system component losses were allocated.

Definitions

- **System Component Losses:** Generated and purchased ("input" or "delivery") Power or Energy (including imports) minus consumed or distributed ("output") Power or Energy.

  Note: *The total generated and purchased energy MegaWatt-hours (MWh) for 2023 and the total MWh delivered (sold) at Each System Component during 2023 were provided by the Accounting Department and Rates Department, respectively. The overall electric system loss percentage is derived from the generated and purchased energy data rather than from system models.*

- **Loss Factor (%):**

$$\left(1 - \frac{\text{Component Output Power or Energy}}{\text{Component Input Power or Energy}}\right) \times 100\%$$

$$= \left(\frac{\text{Component Power or Energy Loss}}{\text{Component Input Power or Energy}}\right) \times 100\%$$

- **Efficiency Factor:**
$[100\% \text{ - Loss Factor } (\%)]$ or $[1 \text{ - Loss Factor (per-unit)}]$

- **Energy Loss Factor:** Total System Component MWh Loss divided by Total System Component MWh Input.

- **Demand Loss Factor:** Average of Monthly Peak System Component MW Losses divided by Monthly Peak System Component MW Inputs.

NOTE: *Average based on twelve monthly peak hours as identified in FERC Form 1, Page 401b.*

- **Cumulative Loss Factor (Energy or Demand):** One minus the product of one minus the per-unit Loss Factor for that system component and one minus the per-unit loss factor for each of the upstream system components. Alternatively, one minus the product of the per-unit efficiency factors for the system component and all upstream system components.

NOTE: *Cumulative loss factors are used to estimate the generation requirements necessary to serve a particular amount of load at any system component.*

Energy Losses - Method

1. Loadflow model cases were created for each of the 8760 hours in the 2023 study year. From each loadflow case (*i.e.* from each hour of the study year), delivery and loss data at points throughout the electric Transmission and High Voltage Distribution (HVD) systems were programmatically collected, processed, and recorded.

2. Utilizing the MWh loss and delivery data, loss percentages for each Transmission or HVD system component were then calculated as:

$$\frac{\sum \text{Component MWh Loss}}{\sum \text{Component MWh Delivery}}$$

3. For Distribution Primary, simulations were run on approximately 2000 circuit models to determine average load and loss data at nine different system gross load levels for all-switched-capacitors-on and all-switched-capacitors-off scenarios. A line loss percentage was calculated from load and loss figures interpolated between the capacitors-on and capacitors-off data, based on the per system load level distribution capacitor schedule (*tone groups*). The line loss, along with Distribution Primary transformer losses calculated in the hourly loadflow cases, comprise the total losses for Distribution Primary.

4. For Distribution Secondary, sales (output) data per system component were provided by Rates Department. Generation requirements (input) per system component were estimated based on cumulative loss percentages previously calculated for each of the other system components. Total system generation requirements were estimated based on an overall system loss percentage derived from Generation and Purchased Power data provided by Accounting Department.

   The difference between the total system estimated generation requirements and the sum of the estimated generation requirements for each system component (except for Distribution Secondary) gives the estimated generation requirement for Distribution Secondary. The difference between Distribution Secondary estimated generation requirements and Distribution Secondary sales gives a cumulative loss percentage, from which the Distribution Secondary loss percentage was derived.

Demand Losses - Method

1. The loss and delivery data from the loadflow cases for the 12 monthly peak hours, as identified in FERC Form 1, were selected and the loss percentages for each Transmission or HVD system component were calculated as the average of ratios of losses to deliveries:

$$\overline{\left(\frac{\text{MW Loss}_{PK}}{\text{MW Delivery}_{PK}}\right)}$$

2. For Distribution Primary, demand line loss percentages for each of the 12 monthly peak hours were calculated similarly as for energy loss. Demand loss percentages were calculated as the average of the loss to delivery ratios, as with the Transmission and HVD system components.

Demand Losses - Method, continued

3. For Distribution Secondary, the ratios of monthly peak MW deliveries to the hourly average MW deliveries were used to estimate an average monthly peak MW delivery per system component. Similar to Distribution Secondary energy loss calculations, an average of monthly peak generation was then estimated from the system component cumulative demand loss percentages. Distribution Secondary average peak generation and, subsequently, cumulative demand loss percentage were estimated, similarly as with energy losses. From that, the Distribution Secondary demand loss percentage was derived.
See “Cumulative Demand Loss Percentages Applied to MWh Deliveries”, page 5, below.

4. Monthly peak demand MW deliveries and losses are tabulated for each system component. The loss factors and cumulative loss factors for each of the 12 monthly peaks were calculated using the previously described methods. For Distribution Secondary, the annual Demand Loss Factor was applied to each of the monthly peak MW deliveries to estimate monthly peak losses and monthly peak Cumulative Loss Factors. Using the annual Distribution Secondary Loss Factor in this manner was necessary since the MWh sales figures used to estimate Distribution Secondary losses are available on an annual, not monthly, basis.

Loss Forecasting

This report details the analysis of electric losses based on historical meter and billing data. No equivalent analysis involving projected future energy demands or power flows is conducted, thus forecasts of future losses are not made. However, several continuous years of electric system loss study results are available, and from these results reasonable inferences about future loss factors could be made.

Losses Applied to MWh Deliveries

1. The cumulative Loss Factors at each system component (Energy and Demand, in per-unit) were used to estimate the generation necessary to provide the given delivery to that system component, per the following formula:

$$\text{Generation} = \frac{\text{Delivery}}{1 - \text{Loss Factor}_{p.u.}}$$

2. The difference between the total power generated and purchased (for the entire system) and the sum of the generation requirements for all system components except Distribution Secondary yielded the cumulative losses for Distribution Secondary. The Loss Factor for Distribution Secondary was then found by rearranging the definition for cumulative losses, as follows:

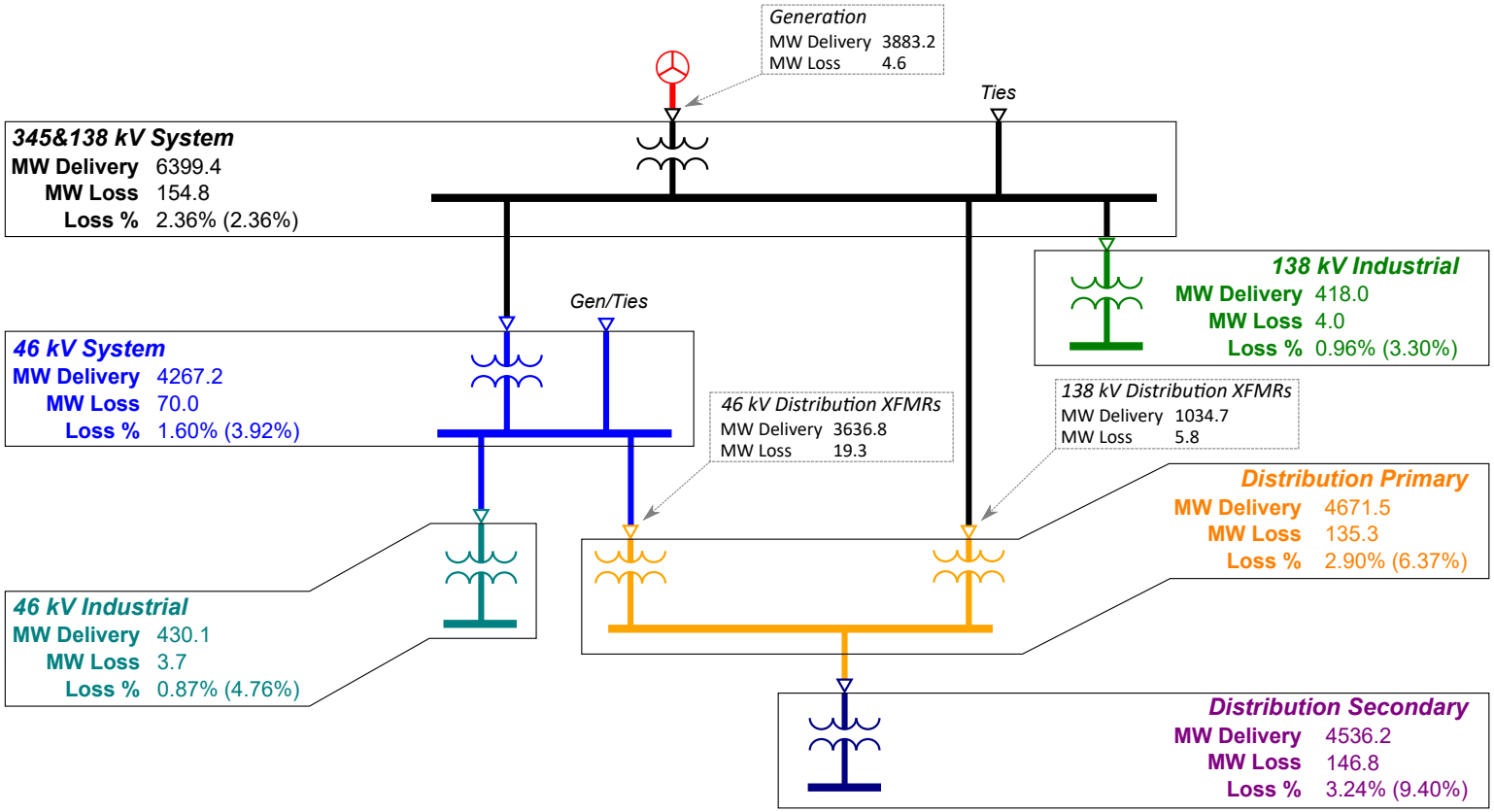
$$\text{Loss Factor}_{Sec.Dist.,p.u.} = 1 - \frac{1 - \text{Cum. Loss Factor}_{Sec.Dist.,p.u.}}{1 - \text{Cum. Loss Factor}_{Pri.Dist.,p.u.}}$$

Loss Mitigation Efforts

Electric system losses are a matter of physics and can never be eliminated. Certain losses, such as transformer core losses, occur whenever the equipment is energized and do not vary with system load level. Capital improvement projects can result in loss reductions by means of moving generation/transmission sources electrically closer to large load centers, converting distribution systems to higher voltages, using larger conductor when replacing line sections, and adding shunt capacitors at load points to improve power factor and reduce current flow. Although capital projects are not typically justified based on loss savings alone, loss savings are considered when evaluating project alternatives. Investments made into programs such as Volt-Var Optimization, Conservation Voltage Reduction, and Energy Waste Reduction are expected to result in loss savings.

DEMAND LOSSES AND DELIVERIES (AVERAGE OF 12 MONTHLY PEAKS)

Combined Method (Each System Component Includes Transformation to that Component)



General Notes

-138 kV Industrial Delivery and Loss does not include HSC volumes
-Monthly loss percentages are calculated as Loss % = (MW Loss/MW Delivery) x 100%
-Loss percentages presented are the average of the monthly loss percentages
-Loss percentages in parentheses are the Cumulative Loss percentages
-Cumulative Loss factors are calculated as one minus the product of one minus the per unit loss factor for that component and all upstream components.
-Loss % for Distribution Primary Lines: 2.37%
-Generation Transformers were combined with the 345 & 138 kV system because all customers are connected at lower voltages (components).

Notes for Distribution Primary and Secondary

-MW Delivery is high-side sum of 138/DST and 46/DST XFMRs
-MW Loss includes 138 & 46 /DST XFMR AND primary line loss
-Cumulative Loss % is adjusted based on the weighted average amount of load served from 138 kV and 46 kV:
First, [(3636.8) x 3.92% + (1034.7) x 2.36%] /(3636.8 + 1034.7) = 3.79%.
Then, [1 − (1 − 0.0290) x (1 − 0.0379)] x 100% = 6.37%
-Distribution Secondary cumulative demand loss % estimated using the average monthly peak deliveries. Refer to estimating sheet (page 5).

CUMULATIVE DEMAND LOSS PERCENTAGES APPLIED TO MWh DELIVERIES

Combined Method (Each System Component Includes Transformation to that Component)

Electrical System Voltage Level	MWh Deliveries (Total)[5]	Average Hourly MW Delivery	Estimated Average Monthly Peak MW Delivery	Cumulative % Demand Loss[4]	Estimated MW @ Generation	% Demand Losses	
138 kV System	511,992	58.4	79	2.36%	80	2.36%	Generation Transformers, 345 &138 kV Systems Combined
V1: >120kV[1&6]	3,168,996	361.8	381	3.30%	394	0.96%	Cum. % = [1-(1-138IND%) x (1-138Sys_cum%)] x 100%
46 kV System[1]	376,054	42.9	61	3.92%	64	1.60%	Cum. % = [1-(1-46Sys%) x (1-138Sys_cum%)] x 100%
V2: 25kV - 120kV[1]	2,892,224	330.2	374	4.76%	393	0.87%	Cum. % = [1-(1-46IND%) x (1-46Sys_cum%)] x 100%
V3: <25kV, Primary Distribution[1&2]	7,518,713	858.3	1264	6.37%	1350	2.90%	Cum. % = [1-(1-DSTprimary%) x (1-46&138AVG_cum%)] x 100%
V4: Secondary Distribution[1,2&3]	19,714,540	2,250.5	3314	9.40%	3658	3.24%	Cum. % = [1-(1-DSTprimary%) x (1-46&138AVG_cum%)] x 100%
	34,182,520	3,902.1	5473		5939	7.85%	

NOTES:

1. The cumulative loss for any level is equal to one minus the product of one minus the per unit loss factor for that level and one minus the per unit cumulative loss factor one level higher.
2. The Cumulative Loss percentages for the Distribution Primary and Secondary were adjusted to account for load served from 138 kV distribution subs. This adjustment was based on a weighted average cumulative loss % from the total MWh delivered to either 46kV/Dist. or 138/Dist.
3. The Distribution Secondary Cumulative Loss % was calculated from the MWh Gen and MWh Del remaining. Then, the Demand Loss % was calculated in reverse from the cumulative.
4. All cumulative loss percentages are calculated assuming the 345 kV and 138 kV Systems are combined along with the Generation Transformers (GSUs)
5. MWh Delivery figures include ROA amounts.
6. V1: >120kV does not include HSC volumes.

MONTHLY DEMAND LOSSES AND DELIVERIES

Combined Method (Each System Component Includes Transformation to that Component)

	PEAKS	Jan 31, 2023 09:00	Feb 03, 2023 09:00	Mar 15, 2023 08:00	Apr 18, 2023 10:00	May 31, 2023 17:00	Jun 01, 2023 16:00	Jul 05, 2023 16:00	Aug 23, 2023 18:00	Sep 05, 2023 16:00	Oct 03, 2023 17:00	Nov 28, 2023 18:00	Dec 18, 2023 18:00
	Deliveries (MW)	3870.7	4599.2	2794.7	1801.9	3656.6	3729.4	4206.9	4989.5	4613.9	2655.8	4078.8	5600.7
GENERATION	Losses (MW)	5.7	6.0	3.9	3.4	4.8	5.3	5.2	4.3	3.6	3.7	2.7	6.8
	Deliveries (MW)	5768.1	5713.4	5364.1	5319.2	7002.3	7218.7	7798.9	7310.0	8349.6	5853.0	5325.1	5770.8
	Losses (MW)	104.1	123.2	81.7	98.5	151.7	178.8	233.1	167.4	299.6	132.6	130.6	157.0
345&138 KV SYSTEM	Loss Factor	1.80%	2.16%	1.52%	1.85%	2.17%	2.48%	2.99%	2.29%	3.59%	2.26%	2.45%	2.72%
	Deliveries (MW)	381.3	400.0	476.1	418.3	427.7	424.7	343.8	506.5	446.7	431.1	415.4	343.8
	Losses (MW)	3.8	4.1	3.9	4.0	4.0	4.1	3.7	4.3	4.2	4.1	4.1	3.6
	Loss Factor	1.00%	1.02%	0.82%	0.95%	0.93%	0.98%	1.08%	0.85%	0.95%	0.96%	0.98%	1.04%
138 KV INDUSTRIAL[3]	Cumulative Loss Factor[2]	2.78%	3.16%	2.33%	2.79%	3.08%	3.43%	4.04%	3.13%	4.50%	3.20%	3.40%	3.74%
	Deliveries (MW)	3740.1	3697.3	3342.0	3262.8	4784.6	4909.5	5430.2	5001.9	5664.2	4106.8	3642.5	3624.1
	Losses (MW)	56.2	55.2	44.7	44.3	80.4	83.4	104.5	89.1	112.2	60.3	54.7	55.4
	Loss Factor	1.50%	1.49%	1.34%	1.36%	1.68%	1.70%	1.92%	1.78%	1.98%	1.47%	1.50%	1.53%
46 KV SYSTEM	Cumulative Loss Factor[2]	3.28%	3.62%	2.84%	3.18%	3.81%	4.13%	4.86%	4.03%	5.50%	3.70%	3.92%	4.21%
	Deliveries (MW)	436.0	429.4	412.9	426.7	439.1	445.3	422.0	469.9	454.9	445.8	394.2	385.2
	Losses (MW)	3.8	3.7	3.6	3.6	3.8	3.8	3.8	4.0	3.9	3.8	3.5	3.5
	Loss Factor	0.88%	0.85%	0.88%	0.85%	0.86%	0.86%	0.89%	0.84%	0.86%	0.85%	0.88%	0.92%
46 KV INDUSTRIAL	Cumulative Loss Factor[2]	4.13%	4.44%	3.70%	4.01%	4.64%	4.96%	5.70%	4.84%	6.31%	4.52%	4.77%	5.09%
	Deliveries (MW)	835.6	870.5	894.3	827.2	1148.4	1210.4	1297.0	1199.8	1392.9	965.5	893.8	881.0
138 KV DISTRIBUTION	Losses (MW)	4.7	4.7	4.9	5.7	6.4	6.7	7.2	6.8	8.1	5.4	4.7	4.7
	Deliveries (MW)	3125.0	3084.9	2766.8	2685.8	4134.4	4240.9	4736.1	4308.9	4935.6	3473.5	3076.7	3073.1
46 KV DISTRIBUTION	Losses (MW)	16.1	15.7	13.9	13.7	22.1	22.9	26.8	23.6	28.5	17.0	15.5	15.4
	Deliveries (MW)	3960.6	3955.5	3661.1	3513.0	5282.8	5451.3	6033.1	5508.7	6328.5	4439.0	3970.5	3954.1
	Losses (MW)	98.7	98.2	88.2	83.1	169.9	178.6	216.4	185.8	239.2	123.3	98.9	97.5
	Loss Factor	2.49%	2.48%	2.41%	2.37%	3.22%	3.28%	3.59%	3.37%	3.78%	2.78%	2.49%	2.46%
DISTRIBUTION PRIMARY	Cumulative Loss Factor[2]	5.39%	5.70%	4.87%	5.17%	6.56%	6.92%	7.88%	6.90%	8.66%	6.07%	5.99%	6.25%
	Deliveries (MW)	3861.9	3857.3	3572.9	3429.9	5112.8	5272.7	5816.7	5322.9	6089.3	4315.7	3871.6	3856.6
	Losses (MW)	125.0	124.9	115.7	111.0	165.5	170.7	188.3	172.3	197.1	139.7	125.3	124.8
	Loss Factor[1]	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%	3.24%
DISTRIBUTION SECONDARY	Cumulative Loss Factor[2]	8.45%	8.75%	7.95%	8.24%	9.58%	9.93%	10.86%	9.91%	11.62%	9.11%	9.03%	9.28%

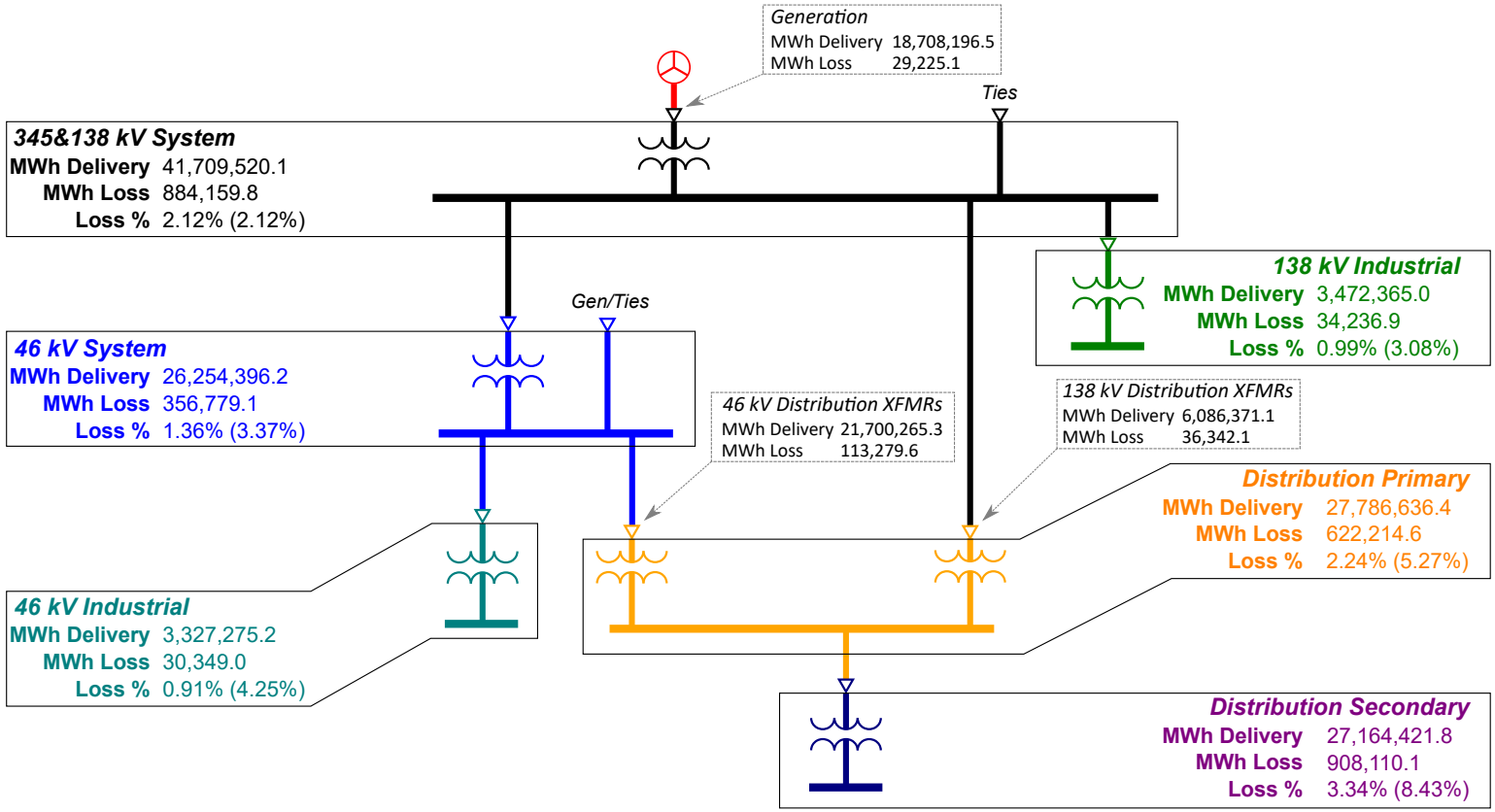
1. The Distribution Secondary Loss factor presented above represents an annual average loss percentage. This Loss factor is applied to each of the 12 monthly peaks to estimate monthly peak demand losses and cumulative demand Loss Factors.

2. See Page 5 for additional notes regarding Cumulative Losses.

3. 138 KV INDUSTRIAL Deliveries and Losses do not include HSC volumes.

ENERGY LOSSES AND DELIVERIES (TOTAL YEARLY MWh)

Combined Method (Each System Component Includes Transformation to that Component)



General Notes

-138 kV Industrial Delivery and Loss does not include HSC volumes
-Loss percentages are calculated as Loss % = (MWh Loss/MWh Delivery) x 100%
-Loss percentages in parentheses are the Cumulative Loss Percentages
-Cumulative Loss factors are calculated as one minus the product of one minus the per unit loss factor for that component and all upstream components.
-Loss % for Distribution Primary Lines: 1.71%
-Generation Transformers were combined with the 345 & 138 kV system because all customers are connected at lower voltages (components).

Notes for Distribution Primary and Secondary

-MWh Delivery is high-side sum of 138/DST and 46/DST XFMRs
-MWh Loss includes 138 & 46 /DST XFMR AND primary line loss
-Cumulative Loss % is adjusted based on the weighted average amount of load served from 138 kV and 46 kV:
First, [(21,700,265.3) x 3.37% + (6,086,371.1) x 2.12%] /(21,700,265.3 + 6,086,371.1) = 3.31%.
Then, [1 − (1 − 0.0224) x (1 − 0.0331)] x 100% = 5.27%

CUMULATIVE ENERGY LOSS PERCENTAGES APPLIED TO MWh DELIVERIES

Combined Method (Each System Component Includes Transformation to that Component)

Electrical System Voltage Level	MWh Deliveries (Total)[5]	Cumulative % Energy Loss[4]	Estimated MWh @ Generation	% Energy Loss	Notes
138 kV System	511,992	2.12%	523,081	2.12%	
V1: >120kV[1&6]	3,168,996	3.08%	3,269,868	0.99%	
46 kV System[1]	376,054	3.37%	389,167	1.36%	
V2: 25kV - 120kV[1]	2,892,224	4.25%	3,020,623	0.91%	
V3: <25kV, Primary Distribution[1&2]	7,518,713	5.27%	7,936,623	2.24%	
V4: Secondary Distribution[1,2&3]	19,714,540	8.43%	21,530,080	3.34%	
TOTAL	34,182,520		36,669,441	6.78%	

NOTES:

1. The cumulative loss for any level is equal to one minus the product of one minus the per unit loss factor for that level and one minus the per unit cumulative loss factor one level higher.
2. The Cumulative Loss percentages for the Distribution Primary and Secondary were adjusted to account for load served from 138 kV distribution subs. This adjustment was based on a weighted average cumulative loss % from the total MWh delivered to either 46kV/Dist. or 138/Dist.
3. The Distribution Secondary Cumulative Loss % was calculated from the MWh Gen and MWh Del remaining. Then, the Demand Loss % was calculated in reverse from the cumulative.
4. All cumulative loss percentages are calculated assuming the 345 kV and 138 kV Systems are combined along with the Generation Transformers (GSUs)
5. MWh Delivery figures include ROA amounts.
6. V1: >120kV does not include HSC volumes.

ENERGY AND DEMAND LOSS PERCENTAGES
4–Year Summary

ENERGY LOSS %	2020	2021	2022	2023	4 yr Avg.
345 & 138 kV System	2.14%	2.01%	2.07%	2.12%	2.08%
138 kV Industrial	0.90%	0.99%	1.00%	0.99%	0.97%
46 kV System	1.34%	1.31%	1.33%	1.36%	1.33%
46 kV Industrial	1.06%	0.95%	0.99%	0.91%	0.98%
Distribution Primary	2.34%	2.40%	2.32%	2.24%	2.32%
Distribution Secondary	4.40%	3.71%	4.25%	3.34%	3.92%

ENERGY LOSS CUMULATIVE%	2020	2021	2022	2023	4 yr Avg.
345 & 138 kV System	2.14%	2.01%	2.07%	2.12%	2.08%
138 kV Industrial	3.01%	2.98%	3.06%	3.08%	3.03%
46 kV System	3.37%	3.22%	3.30%	3.37%	3.31%
46 kV Industrial	4.39%	4.14%	4.26%	4.25%	4.26%
Distribution Primary	5.32%	5.26%	5.26%	5.27%	5.27%
Distribution Secondary	9.48%	8.77%	9.28%	8.43%	8.99%

DEMAND LOSS %	2020	2021	2022	2023	4 yr Avg.
345 & 138 kV System	2.50%	2.29%	2.16%	2.36%	2.33%
138 kV Industrial	0.88%	0.96%	1.03%	0.96%	0.96%
46 kV System	1.62%	1.56%	1.58%	1.60%	1.59%
46 kV Industrial	0.99%	0.91%	0.96%	0.87%	0.93%
Distribution Primary	2.86%	2.92%	2.81%	2.90%	2.87%
Distribution Secondary	3.55%	3.65%	3.96%	3.24%	3.60%

DEMAND LOSS CUMULATIVE%	2020	2021	2022	2023	4 yr Avg.
345 & 138 kV System	2.50%	2.29%	2.16%	2.36%	2.33%
138 kV Industrial	3.36%	3.23%	3.17%	3.30%	3.26%
46 kV System	4.08%	3.81%	3.71%	3.92%	3.88%
46 kV Industrial	5.03%	4.68%	4.64%	4.76%	4.78%
Distribution Primary	6.43%	6.27%	6.06%	6.37%	6.28%
Distribution Secondary	9.75%	9.69%	9.78%	9.40%	9.66%

General Notes

- Annual Loss percentages are calculated as Loss % = [MW(h) Loss/MW(h) Delivery] x 100%
- Annual Cumulative Loss percentages are calculated as one minus the product of one minus the per unit Loss Factor for that component and for all upstream components.
- 4-year Average Loss percentages and Cumulative Loss percentages are the averages of the annual loss percentages.

Mitigating Wildfire Risk in Consumers Energy's Service Territory (2025-2029)

June 2025

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Executive Summary

Consumers Energy has proudly served Michigan families and businesses since 1886, with more than 1.9 million electric customers across the state today. The Company is committed to providing an electric distribution system that delivers safe, reliable, clean, and affordable electricity to customers today and in the future. To do that, Consumers Energy must address the growing wildfire risk brought on by the changing climate in Michigan[1].

Over the last decade, wildfires have grown in number and severity throughout the United States, and become a significant public health and safety concern.

In the last 13 years, there have been more than 100 wildfires in Michigan's lower peninsula each year, burning more than 2,000 acres in seven of those 13 years, and more than 2,000 acres in three of the last four years.[2] Given these trends, the Company developed this plan to mitigate destructive wildfire risk in Consumers Energy's electric territory.

Consumers Energy is guided by its ambition to deliver world class performance delivering hometown service, measured by our triple bottom line of people, planet, and Michigan's prosperity. Our triple bottom line balances the interests of customers with other stakeholders and captures the broader societal impacts of the Company's activities.

Purpose

This plan describes the Company's approach to mitigate the risk of wildfires caused by or impacting electrical infrastructure and surrounding communities throughout Consumers Energy's service territory, with safety as the top priority.

The Company first identified the growing risk of wildfires as a result of changing weather patterns in the Reliability Roadmap published in September 2023[3] and subsequently created this plan to mitigate that risk.

This document outlines the plans and actions Consumers Energy will seek to take to further develop competencies, invest in system hardening, and expand existing programs such as line clearing to alleviate the pressure from increased wildfire risk.

The goal is the overall safety of the customers and communities we serve, and the Consumers Energy employees who serve them.

This plan will continue to evolve as the Company learns more about wildfire risk in Michigan, new wildfire risk reduction strategies and technologies, and how changing weather patterns impact the region.

[1] Wildfire Weather: Analyzing the 50-year shift across America, May 2023 - www.climatecentral.com
[2] Michigan Department of Natural Resources - Fire Report Dashboard
[3] MPSC Case No. U-20147

Objectives

Consumers Energy is driven to be an excellent corporate citizen for the state of Michigan and that means not only providing safe, reliable electricity to our 1.9 million customers but also actively making the communities we serve safer.

Our objective is to improve our distribution system to provide reliable energy delivery to our customers while hardening and protecting it against wildfire ignition risks. This will be accomplished by expanding current and investing in new programs and competencies to mitigate risk. To do this Consumers Energy intends to:

- Understand the current and probable wildfire risk areas in our service territory through development and maturity of assessment tools.
- Implement mitigation solutions that balance the risk of wildfires with safe and reliable energy delivery.
- Leverage existing programs, such as line clearing, to deliver benefits beyond reliability and resiliency.
- Implement procedures to inform customers and communities of wildfire preparedness measures and communication protocols in the event of a wildfire risk event, i.e., *Red Flag Warnings*.
- Engage customers and communities in the ongoing development of the wildfire risk mitigation plan, particularly as it relates to ensuring customer safety and electric reliability.
- Continuously improve this plan by leveraging industry experts and peers and learning about and deploying best practices.

Wildfire Risk Mitigation Activities

To meet Consumers Energy's wildfire risk mitigation plan objectives, the Company is focused on the following:

- **Situational Awareness:** Monitor weather, any heightened wildfire risk warnings (including *Red Flag Warnings*), and conditions on the Low Voltage Distribution ("LVD") system to respond to wildfire risks.
- **Operational Procedures:**
    - *Field Operations:* Use modified field operating procedures to reduce the risk of ignition from utility infrastructure or operations, and to ensure the safety of our employees.
    - *Recloser Settings:* Employ procedures to mitigate spark risk on the distribution system during elevated wildfire risk periods.
    - *Public Safety Power Shutoff:* Design a plan to allow us to de-energize specific areas of the distribution network during extreme wildfire risk periods to pre-emptively eliminate potential spark risk from Consumers Energy's distribution system.
    - *Emergency Preparedness:* Deploy a wildfire-specific emergency action plan to enable Emergency Management to act quickly in case of wildfire danger.

- **System Hardening:**
    - *Undergrounding:* Convert portions of the overhead distribution system to underground using specific criteria designed to identify line segments with the highest potential to eliminate wildfire risk associated with overhead conductor.
    - *Covered Conductor:* Install covered conductor and other LVD construction methods in elevated risk areas to reduce chance of spark or arcing, which would result in a potential ignition due to contact with another conductor, animal, vegetation, or any other material.
    - *Protective Line Devices:* Install non-expulsion fuses to limit spark when a fuse opens as well as remotely controlled line reclosers or other devices to increase sectionalization and control of LVD lines in the elevated wildfire risk areas.
- **Line Clearing:** Implement a 5-year clearing cycle for the LVD system, including a more aggressive timeline to achieve this cycle in elevated wildfire risk areas better to manage growth and limit potential vegetation-to-conductor contact. Capture Light Detection and Ranging ("LiDAR") imagery to inform and support line clearing tactics.

Figures 1 and 2 summarize the estimated costs for Consumers Energy's proposed wildfire risk mitigation activities over the next five years. This plan grows to $60 million in capital and approximately $615,000 in O&M as the Company builds its capabilities to mitigate wildfire risk.

Given the Commission order in Case No. U-21585 requiring more support to substantiate capital investment in mitigating wildfire risk, the Company will provide more detail on the value of Wildfire Risk Mitigation in an upcoming regulatory filing with the intent to increase capital investment for the mitigation of wildfire risk in 2027. This lack of capital approval eliminates System Hardening from the benchmarked best practice activities the Company can leverage in mitigation of wildfire risk, leaving only O&M related practices.

Figure 1

Consumers Energy's Wildfire Risk Mitigation Capital Investment Plan

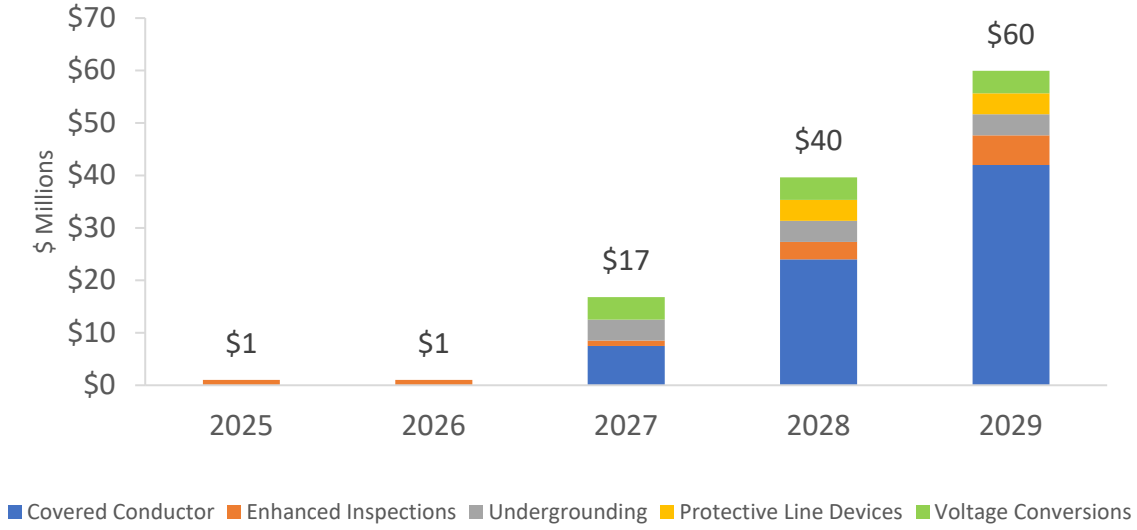
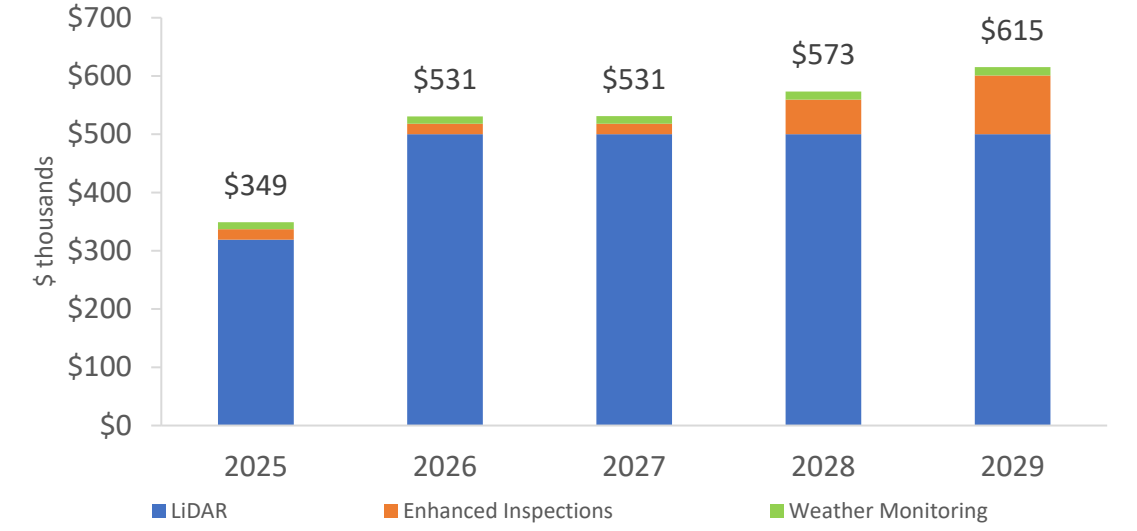


Figure 2

Consumers Energy's Wildfire Risk Mitigation O&M Plan



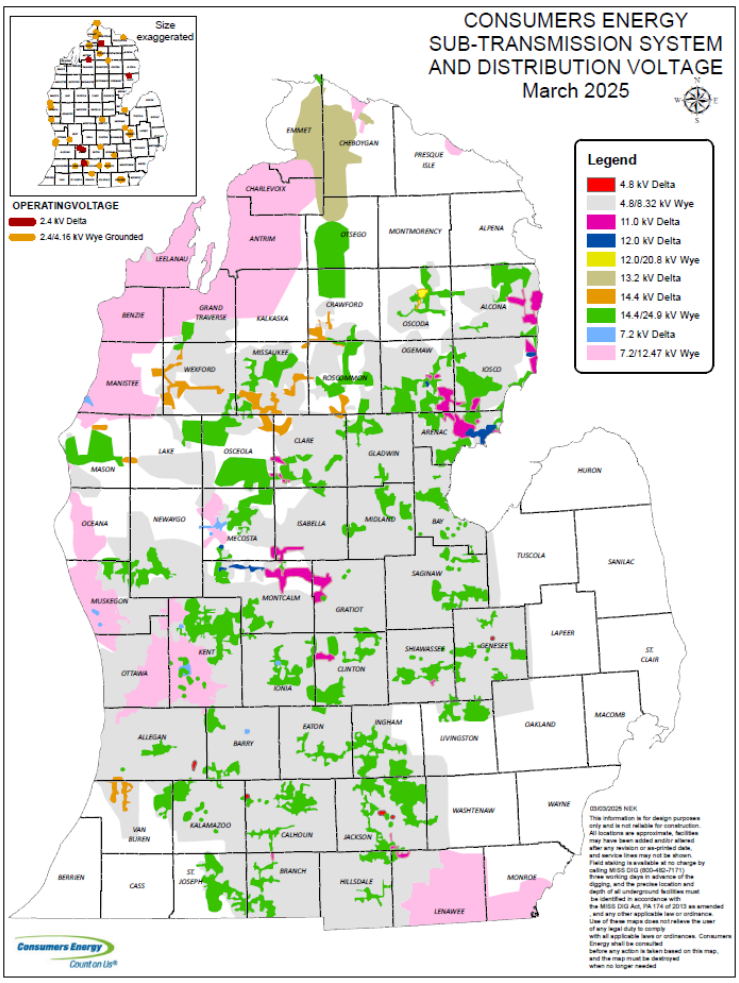
Risk Assessment and Mapping

Consumers Energy Service Territory Overview

The Company's electric distribution system is an essential part of Michigan's infrastructure, serving 1.9 million customers across more than 111,300 miles of distribution lines and 1,135 substations in the north, central, and western portions of Michigan, from Monroe County to Mackinaw City, as shown in Figure 3.

Figure 3

Consumers Energy's Electric Service Territory



The distribution system is functionally separated by operating voltage into High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD").

- HVD operates at the highest voltages, taking electricity from regional transmission companies, and transporting it across miles of lines, where it connects into the LVD system at 828 substations throughout the Company's service territory.
- At LVD substations, high voltage is 'stepped down' (or reduced to lower voltages) onto the LVD system. LVD voltage is then further stepped down at secondary distribution transformers to secondary voltages (120 to 480 Volts), serving businesses and residences.

The LVD system is comprised of more than 111,300 total miles of lines, made up of approximately 61,600 miles of primary overhead and underground (carries electricity from substations to transformers), and 49,700 miles of secondary (carries electricity from distribution transformers to customers).

The HVD system is comprised of approximately 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines, 19 miles being 46 kV underground lines, and approximately 200 miles being 138 kV overhead lines, and 4 miles being 138 kV underground lines.

Wildfire History within Consumers Energy's Service Territory

Consumers Energy has used historical wildfire information from 2012 through 2024 from the Michigan Department of Natural Resources combined with the Federal Emergency Management Agency ("FEMA") *National Risk Index* map to continue growing our knowledge and understanding of wildfire risk in Consumers Energy's service territory.

The wildfire risk in Michigan, based on the FEMA index map, identifies the majority of the upper and lower peninsulas as having some wildfire risk.

Within the areas served by Consumers Energy, the highest wildfire risk regions span 17 counties in the western and northern lower peninsula; however, historically, wildfires can occur throughout the lower peninsula. For instance, the Thumb Fire, also known as The Great Fire of 1881, burned more than 1 million acres in less than a day, with nearly 300 people[4] losing their lives. It also destroyed more than 1,500 dwellings and stranded over 14,000 people[5].

Over the last 13 years, more than 2,700 wildfires in the lower peninsula burned nearly 24,000 acres. Three of the last four years have seen more than 2,000 acres burned each year, and during four of the last seven years more than 2,000 acres burned.[6]

Several wildfires in recent history have burned multiple thousands of acres, and significantly impacted the northern lower peninsula:

- 2023 Wilderness Trail Fire – Burned approximately 2,400 acres, closed I-75, necessitated flight restrictions below 5,000 feet; was caused by a campfire, and required Consumers Energy to de-energize a 46kV line, interrupting service to almost 3,000 customers.
- 2022 Blue Lakes Fire – Burned 2,500 acres, closed multiple roads in the area, and was caused by a lightning strike.
- 2010 Meridian Boundary Fire – Burned more than 8,800 acres and 51 structures, closed multiple roads in the area, and was caused by burning debris.

To understand the timing of historical wildfires in the lower peninsula of Michigan, Consumers Energy evaluated the average number of wildfires by month and number of days *Red Flag Warnings* were issued by the National Weather Service.

[4] Deadliest Wildfires in U.S. History | WFCA
[5] Fires ravaged Michigan's thumb in 1871, 1881 | University of Michigan News (umich.edu)
[6] Michigan Department of Natural Resources - Fire Report Dashboard

The National Weather Service declares *Red Flag Warnings* when there are "warm temperatures, very low humidities, and stronger winds that are expected to combine to produce an increased risk of fire danger"[7]. Contributing Red Flag Factors include:

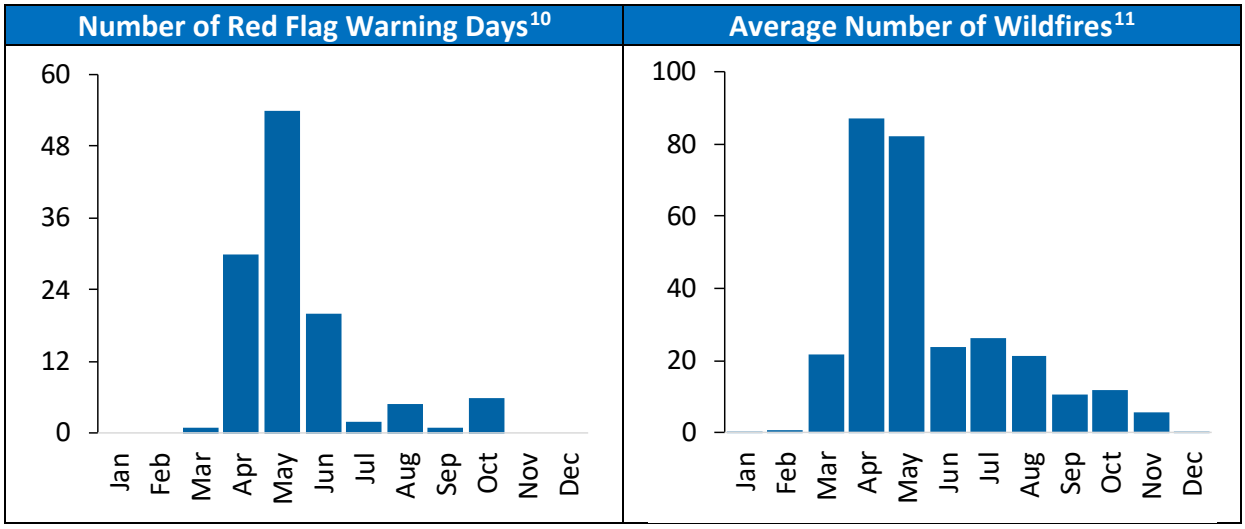
- First significant lightning occurrence after a hot and dry period.
- Significant cold frontal passage, expected to cause strong sustained and gusty winds, and an abrupt wind shift.
- Any combination of weather and fuel conditions that would create a critical fire control situation or extensive wildfire outbreak.[8]

As shown in Figure 4, the number of days with *Red Flag Warnings* issued is highest April through June and corresponds with the average number of wildfires by month being highest in March through August.

Based on historic wildfire data, a wildfire is more likely to occur in the spring when underbrush and trees are dry and not yet green, and in the late summer when it becomes drier throughout the state. Given continued climate change, the drying trend will continue to worsen.[9]

Figure 4

Red Flag Warnings and Wildfires in Michigan (2006-2024)



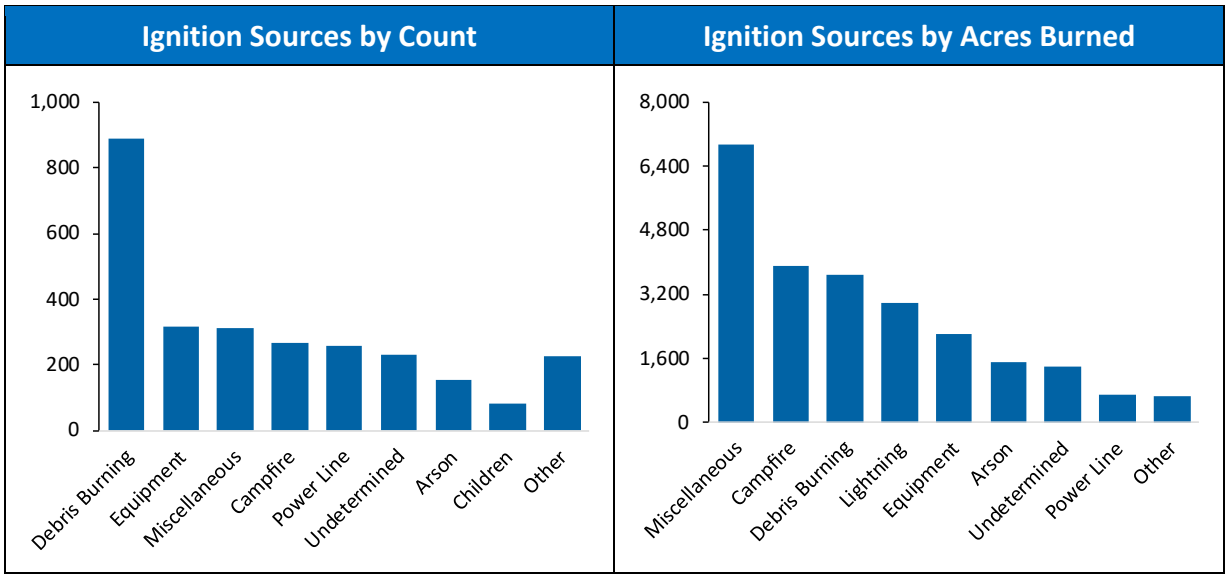
Over the last 13 years, debris burning has been the number one cause of wildfires in the lower peninsula of Michigan with equipment, miscellaneous, campfires, and power lines rounding out the top five causes as shown in Figure 5.

Based on the data from the Michigan Department of Natural Resources, power lines have caused approximately 9% of all wildfires over the last 13 years.

[7] Red Flag Warning (weather.gov)
[8] National Weather Service Red Flag Program (Fire Weather Criteria)
[9] Fifth National Cimate Assessment Ch. 4 Water
[10] Iowa Environmental Mesonet of Iowa State University - https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml
[11] Michigan Department of Natural Resources Fire Report Dashboard

Figure 5

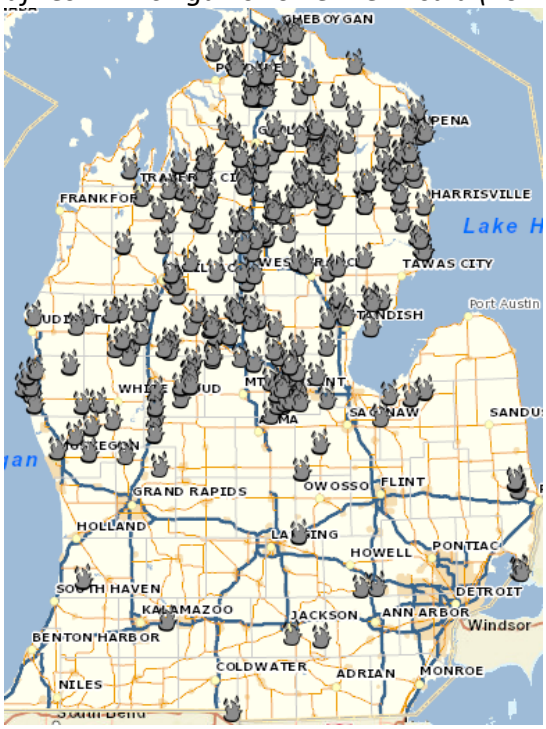
Wildfire Ignition Sources in Michigan's Lower Peninsula (2012-2024) [12]



The map in Figure 6 below shows where wildfires occurred throughout Michigan's lower peninsula in 2023. The majority of these wildfires took place in the northern part of the lower peninsula.

Figure 6

Wildfires in Michigan's Lower Peninsula (2024)[13]



[12] Michigan Department of Natural Resources Fire Report Dashboard

[13] Department of Natural Resources (DNR Wildland Fire map)

It is also important to understand Michigan's fire regime and what it means for Michigan's wildfire risk profile.

A *fire regime* refers to the pattern, frequency, and intensity of wildfires in a specific area over long periods of time. In Michigan, particularly within the Consumers Energy service territory, the overall Fire Regime Condition Class ("FRCC") ranges from FRCC 0 to FRCC 5. The lower the FRCC, the more likely a major or catastrophic fire is to occur. This classification is based on the history of fires in a particular area, as well as the fuel load and type.

In areas of Michigan that are largely unforested or consist mainly of hardwoods, such as oak and maple with minimal shrubbery, the frequency and intensity of fires tend to remain low. Conversely, in regions dominated by softwoods, such as the Jack Pine forests of north-central Michigan, the frequency and intensity of fires are higher.

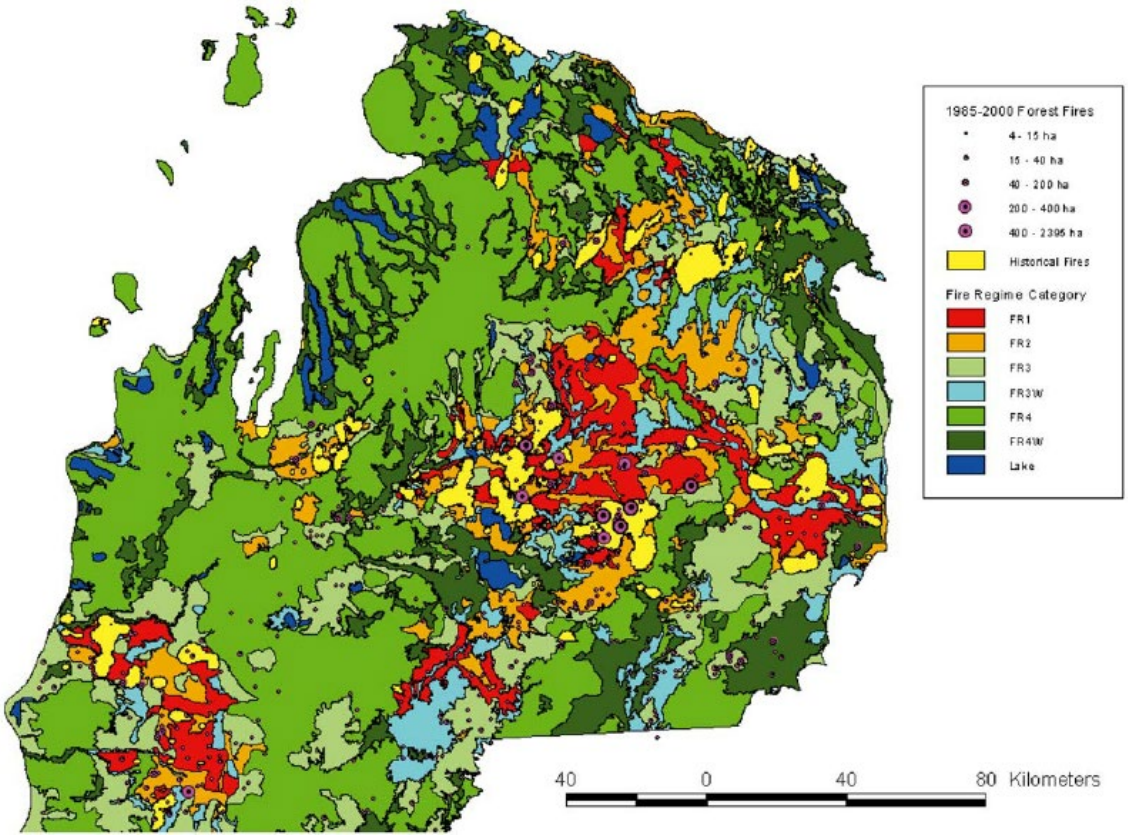
Understanding the history of fires allows for better fire management. Not all fires are bad. For instance, in Northern Michigan, Jack Pine forests rely on the heat from a fire to open and release seeds. This is one reason why the Michigan Department of Natural Resources and the United States Forest Service will conduct prescribed burns.

Looking at the map below in Figure 7, we can understand the different regime boundaries throughout the state based on the history of fires, and can focus more resources on prevention in the higher regime areas that are more likely to be impacted by large, intense fires.

Please note, the map below runs from 1908-2000. In the last 25 years, more fires have impacted northern Lower Michigan including the 4 Mile Road fire (2008, 1,000 acres), Meridian Boundary Fire (2010, 8,586 acres), The Wilderness Trail Fire (2023, 2,442 acres), and Blue Lakes Fire (2022, 2,516 acres).

Figure 7

Historical Fire Boundaries and Fire Regime Categories of Northern Lower Michigan[14]



The map in Figure 7 focuses on the northern portion of the state. This is not saying that the southern areas are not prone to wildfires, but that intense fires and fuel load availability are rare. Typically, these areas in the southern areas have an FRCC rating of 3 or 4.

Wildfire Risk Assessment

Generally, risk encompasses the likelihood of an event together with the impact of that event.

The likelihood of a wildfire event depends on factors such as ignition risk, fuel source availability, and weather conditions. The impact of a wildfire event includes public safety, physical structures, and environmental consequences.

FEMA publishes a *National Risk Index* map that includes a Wildfire Risk Index score and rating for the United States, representing a community's relative risk for wildfires when compared to the rest of the United States[15].

[14] Cleland, David & Crow, Thomas & Saunders, Sari & Dickmann, Donald & Maclean, Ann & Jordan, James & Watson, Richard & Sloan, Alyssa & Brosofske, Kimberley. (2004). Characterizing historical and modern fire regimes in Michigan (USA): A landscape ecosystem approach. Landscape Ecology. 19. 311-325. 10.1023/B:LAND.0000030437.29258.3c.

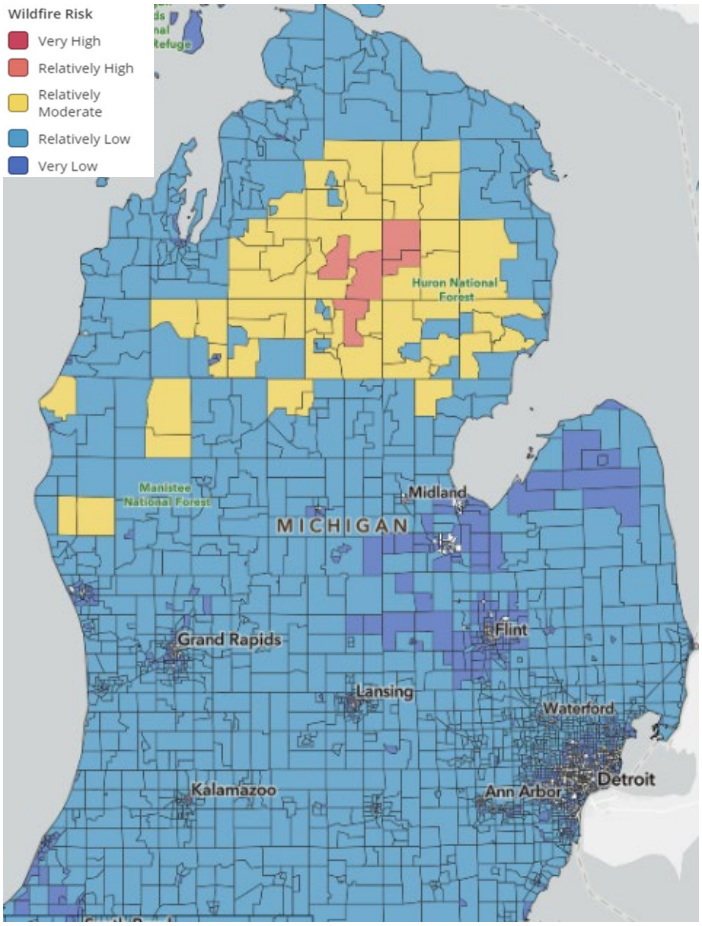
[15] Wildfire | National Risk Index (fema.gov)

According to FEMA's *National Risk Index* map, approximately 21% of Consumers Energy's territory and approximately 95,000, or 5% of our customers are located within an elevated wildfire risk area. This elevated wildfire risk area is primarily in the north central and midwestern part of the lower peninsula as shown in Figure 8.

While FEMA identifies the majority of Michigan's lower peninsula as having some wildfire risk, Consumers Energy is defining the areas FEMA classifies as 'Relatively High' and 'Relatively Moderate' as the areas with elevated wildfire risk.

Figure *8*

Elevated Wildfire Risk Areas in Michigan's Lower Peninsula [16]

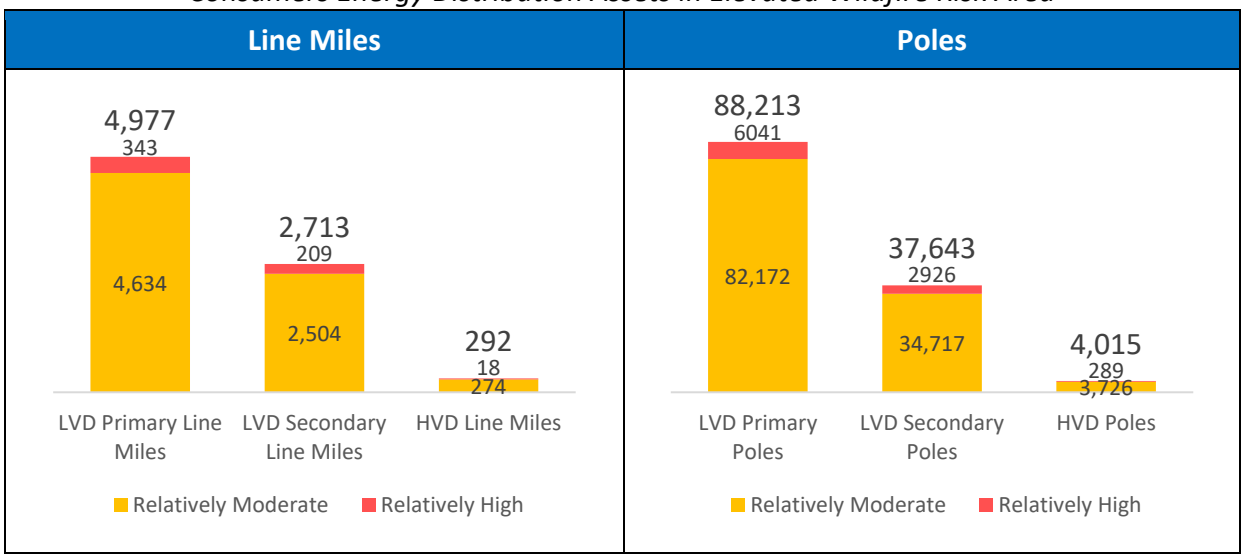


- Within the elevated wildfire risk areas identified in the FEMA *National Risk Index* map, nearly 7% of Consumers Energy's distribution line miles are exposed.
- This is comprised of approximately 7,690 miles of LVD lines and 292 miles of HVD lines on 125,856 LVD poles and 4,015 HVD poles as shown in Figure 9.

[16] FEMA National Risk Index (https://hazards.fema.gov/nri/map)

Figure *9*

Consumers Energy Distribution Assets in Elevated Wildfire Risk Area



To ensure the initial mitigation activities outlined in this plan are implemented in the highest risk areas first, the Company will leverage internal and external data sources to refine ignition risk, fuel source availability, and weather conditions specific to Consumers Energy's territory.

- To better understand weather conditions, the Company uses a wildfire-specific weather forecast from DTN, a third-party weather service that is widely used in the utility industry to forecast and monitor severe weather, and the Company monitors *Red Flag Warnings by the National Weather Service*. This is described in more detail in the Situational Awareness section below.
- To better understand ignition risk, the Company uses historical hazard event information such as wire downs, tree on line, object on line, etc., to identify specific mitigation efforts to prioritize throughout the elevated risk areas identified by FEMA in the Company's service territory. The Company will consider the characteristics and condition of electrical lines and equipment, the frequency and distribution of electrical outages, the distribution and density of vegetation dry fuel sources, and localized weather patterns to identify these elevated risk areas with high specificity and granularity.
- To build sophisticated wildfire risk assessment models, the Company will capture and track asset health data using the Asset Investment Planning ("AIP") and asset repository projects currently being implemented. To support all or part of their risk assessment modeling, many utilities in the Western United States use third-party vendors analyzing hundreds of thousands of asset health data inputs and employing machine learning and other advanced techniques. Consumers Energy will evaluate these options after assessing the implemented AIP and asset repository projects.

- To better understand the historical powerline-caused wildfire data to incorporate insights into the analysis, the Company is in contact with the Michigan Department of Natural Resources ("DNR").

Additionally, the Company will collaborate with agencies such as the Michigan DNR, local fire departments, and county emergency managers, to ensure alignment regarding the elevated wildfire risk areas in Michigan and a cohesive effort to reduce wildfire risk in Michigan.

Opportunities to Evaluate

Currently, the FEMA *National Risk Index* map is used in identifying elevated wildfire risk areas to focus on mitigation.

Consumers Energy will identify assets vulnerable to wildfire within elevated wildfire risk areas by using Company-specific asset health information in addition to the data sources mentioned earlier in this section. The Company will perform this analysis internally to reduce costs and to leverage our internal expertise. This approach capitalizes on the Company's experience while also enhancing our understanding and capabilities in this area.

To identify areas with elevated ignition risk, the Company may consider its electrical lines and assets on a circuit-by-circuit basis using the data from the AIP project.

- In the short term, data from historical fault distributions and frequencies combined with historical hazard information can be used in conjunction with historical ignition and FEMA data to develop baseline risk levels for different areas of the Company's service territory.
- Factors such as asset age and distance from a substation can be considered to characterize the potential energy released at fault locations.
- Localized weather patterns such as wind gust intensities (that can contribute to wire-to-wire contact) and hot/dry day frequencies can be analyzed to further characterize the ignition risk in these areas. The Company may also consider the impact of vegetation dry fuel sources on ignition risk.

With more Consumers Energy-specific information, mitigation activities and investments can be increasingly targeted, and emergency agencies can be made aware of potential risks to public safety, physical structures, the environment, and the electric distribution system—all of which will serve to mitigate wildfire ignition and spread.

Situational Awareness

Situational awareness is the action the Company takes to monitor weather conditions and asset health in elevated wildfire risk areas to support both real-time and longer term operational and investment decisions.

There are a number of situational awareness tools specifically used to mitigate wildfire risk that the Company has identified through benchmarking efforts with other utilities. These include:

- Wildfire-specific weather monitoring
- Weather stations

- Staff meteorologists
- Enhanced inspections
- Fire detection cameras
- Fire spread modeling
- Enhanced wildfire risk modeling

Consumers Energy is currently focused on leveraging weather monitoring, a staff meteorologist, line sensors, and enhanced inspections to mitigate wildfire risk.

The Company will continue to evaluate additional situational awareness tools such as expanded use of drones, fire detection cameras, and downed conductor detection technology.

Weather Monitoring

Weather monitoring is critical for wildfire risk mitigation as it helps identify areas and levels of concern that may be used to respond quickly and effectively to real-time changing weather conditions and prioritize mitigation activities.

Consumers Energy has expanded its weather monitoring program to include reviewing *Red Flag Warnings,* using a wildfire-specific weather forecast from DTN, and has hired an on-staff Company meteorologist.

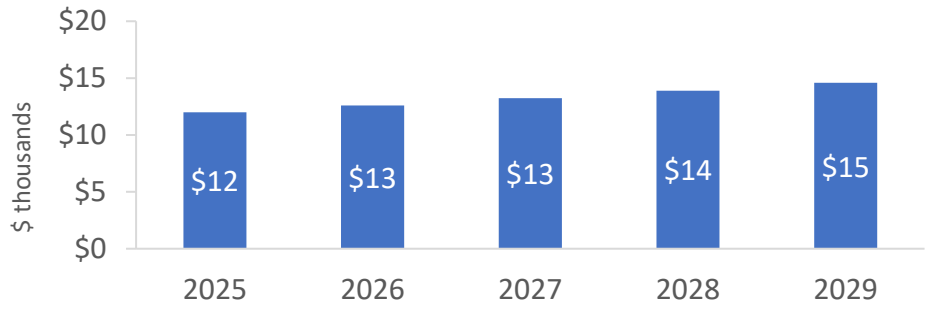
Wildfire-specific weather forecast data is emailed by DTN to the Company twice per day and used to facilitate real-time adjustments to operational procedures as well as allow the Company to begin collecting territory-specific wildfire weather data to incorporate into ongoing wildfire risk assessments. The meteorologist continuously monitors and assesses weather and fire risk conditions. Continuous assessment and weather monitoring, along with situational awareness, may involve, but is not limited to, reviewing information from sources such as DTN, NWS, MesoWest, and DNR sites.

To further enhance wildfire monitoring, the Company plans to install weather stations in areas of high risk. This strategy is detailed in the Company's Reliability Roadmap.

The costs for the wildfire-specific weather forecast from DTN are shown in Figure 10 below.

Figure 10

Weather Monitoring O&M Plan



Line Sensors

Line sensors are inductively charged devices installed on the overhead primary conductor of the LVD distribution system. They are used to remotely monitor electrical current and detect sustained, momentary, and potential faults, improving the capability to respond quickly and reduce customer outages. Line sensors also capture data points such as amperage, conductor temperature, phase imbalance mis-phasing, and load flow direction.

Adding line sensors to LVD distribution lines in the elevated wildfire risk area will allow the Company to reduce ignition risk by remotely monitoring the current conditions of the distribution primary conductor, as well as monitoring for potential faults, which will allow the Company to quickly respond before a failure occurs.

Consumers Energy has prioritized the relatively high and relatively moderate wildfire risk areas for the installation of line sensors on circuits. The Company will continue to evaluate opportunities to install additional line sensors on these circuits to provide additional insight and remote monitoring capabilities.

Enhanced Inspections

'Enhanced inspections' refer to increasing the frequency of LVD line inspections and correcting identified failures to reduce wildfire risk. Line inspections are currently conducted on a two-year cycle and include visually observing LVD distribution lines and supporting infrastructure to identify potential issues with equipment.

Consumers Energy is increasing LVD line inspections to an annual cycle in the Relatively High wildfire risk areas starting in 2025, and ramping up to an annual cycle in the Relatively Moderate risk areas in 2028 and 2029.

By increasing the frequency of inspections in the Relatively High wildfire risk areas**,** and shortly thereafter increasing the frequency in the Relatively Moderate wildfire risk areas, the Company will reduce risk by identifying and mitigating the potential for ignition risk as well as fuel sources such as dead trees and overgrown vegetation.

As stated in the Company's Reliability Roadmap, Consumers Energy will improve the inspection process, using drones in a much more widespread manner, while investing in automation and machine learning to increase the efficiency with which defects are identified. The enhanced inspections in elevated wildfire risk areas will benefit from these advancements.

In 2024, the Company prioritized circuits located in the elevated wildfire risk areas in the inspection plan, as well as put resources and plans in place to start inspecting all circuits in the Relatively High wildfire risk areas annually starting in 2025 so as to complete the majority of inspections prior to the Spring when a wildfire is more likely to occur.

Figure 11 below shows the 5-year capital plan for enhanced inspections. When an LVD line demand failure is identified as the result of an inspection, this is the cost to correct the failure.

Figure 11

Enhanced Inspections Capital Plan

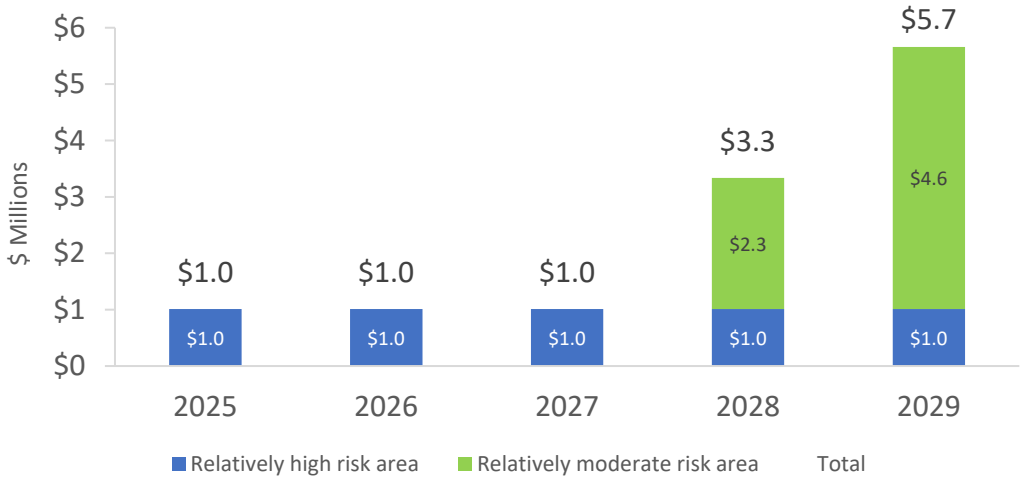
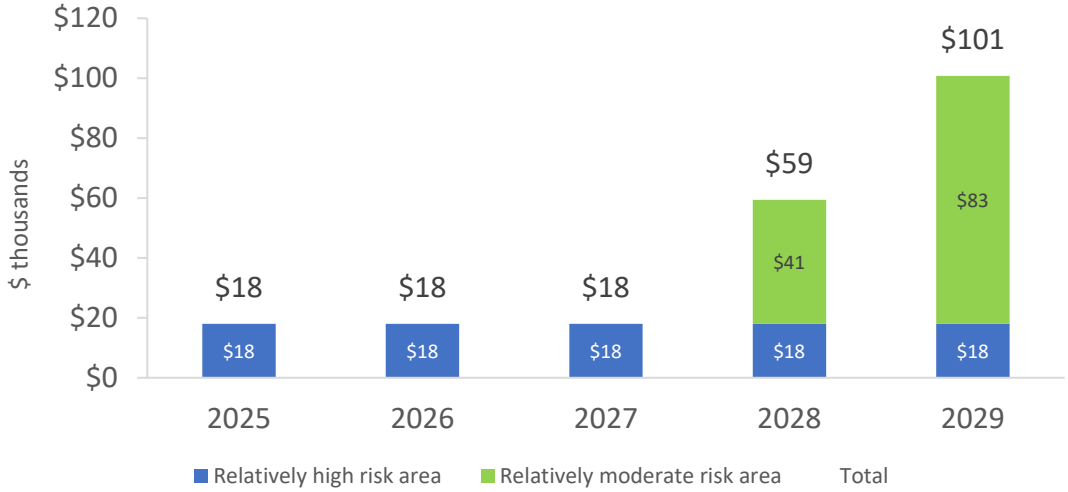


Figure 12 shows the 5-year O&M plan to perform inspections on an annual cycle as opposed to the existing, two-year cycle.

Figure 12

Enhanced Inspections O&M Plan



Opportunities to Evaluate

The Company will continue to evaluate other situational awareness tools such as Company-owned weather stations, expanded use of drones, fire detection cameras, and downed conductor detection technology as well as continue to benchmark and collaborate with Edison Electric Institute ("EEI") and Electric Power Research Institute ("EPRI") to identify new technologies and best practices for wildfire risk mitigation.

Company-owned weather stations allow a utility more control and access to more granular weather information. Currently, weather and hazard forecast information is provided by DTN by regions that consist of several counties as shown in Figure 13. This broad view limits the Company's ability to understand in detail. Peer assessments have shown that more granular weather information is beneficial when tracking wildfire risk because both the risk assessment and mitigations can be more specific.

Company-owned weather stations located at substations would allow the Company to measure wildfire risk and take mitigation actions in a more targeted way, reducing the negative reliability impacts of some mitigation activities to customers.

Consumers Energy is proposing Company-owned weather stations in the electric rate case, Case No. U-21870, to support storm response as well as the Company's overall reliability efforts as described in the Company's Reliability Roadmap. The Company will be able to leverage these weather stations for wildfire risk mitigation.

Figure 13

Example of DTN Weather Forecast Report including Wildfire Forecast

Parameter	Region	Day 1	Day 2	Day 3	Day 4	Day 5
Wind Speed	Bay Central	1	1	1	1	1
	Eastern	1	1	1	1	1
	Grand Rapids	1	1	1	1	1
	Lakeshore	1	1	1	1	1
	Northeast	1	1	1	1	1
	Northwest	1	1	1	1	1
	Southern	1	1	1	1	1
	Southwest	1	1	1	1	1
Wind/Gust	Bay Central	1	2	1	1	1
	Eastern	1	2	1	1	1
	Grand Rapids	2	2	1	1	1
	Lakeshore	2	2	1	1	1
	Northeast	1	1	1	1	1
	Northwest	2	2	1	1	1
	Southern	2	2	1	1	1
	Southwest	2	2	1	1	1
Wildfire	Bay Central	4	1	1	1	1
	Eastern	4	1	1	1	1
	Grand Rapids	4	1	1	1	1
	Lakeshore	4	1	1	1	1
	Northeast	4	1	1	1	1
	Northwest	4	1	1	1	1
	Southern	4	1	1	1	1
	Southwest	4	1	1	1	1
Snow	Bay Central	1	1	1	1	1
	Eastern	1	1	1	1	1
	Grand Rapids	1	1	1	1	1
	Lakeshore	1	1	1	1	1
	Northeast	1	1	1	1	1
	Northwest	1	1	1	1	1
	Southern	1	1	1	1	1
	Southwest	1	1	1	1	1
Ice	Bay Central	1	1	1	1	1
	Eastern	1	1	1	1	1
	Grand Rapids	1	1	1	1	1
	Lakeshore	1	1	1	1	1
	Northeast	1	1	1	1	1
	Northwest	1	1	1	1	1
	Southern	1	1	1	1	1
	Southwest	1	1	1	1	1
Confidence Level	Bay Central	Medium	Medium	High	High	High
	Eastern	Medium	Medium	High	High	High
	Grand Rapids	Medium	Medium	High	High	High
	Lakeshore	Medium	Medium	High	High	High
	Northeast	High	Medium	High	High	High
	Northwest	Medium	Medium	High	High	High
	Southern	Medium	Medium	High	High	High
	Southwest	Medium	Medium	High	High	High

Company-owned weather stations may be positioned in a way to extract territory-specific real-time weather data that can be recorded to allow staff meteorologists to specialize in real-time weather patterns as well as analyze historical data trends in Consumers Energy's territory.

Additional localized detail would create more insight into weather conditions that lead to wildfire risk, and would allow the Company to refine operational procedures and better target system hardening to enhance wildfire risk mitigation.

Drones can be used in a variety of ways to expedite or enhance inspections and investigations as described in the Company's Reliability Roadmap. One way the Company may consider using drones to reduce wildfire risk is to use a thermal camera drone to detect hotspots or failing equipment invisible to the naked eye. This technology may be particularly useful during outage or disturbance investigations. The Company will continue to evaluate the benefit using thermal camera drones in the elevated wildfire risk area.

Fire detection cameras are automated cameras connected to an artificial intelligence engine that detects smoke within a specific mileage radius.

- These cameras support wildfire risk mitigation by sending fire location information to any stakeholders identified to receive the information.
- This early warning and detection technology is used by many utilities in the western part of the United States who have distribution and transmission systems in less densely populated areas to find and respond to wildfires quickly and effectively.

The Company would need approximately 135 cameras to adequately cover the elevated wildfire risk areas at a cost of approximately $7 million. Consumers Energy will continue to evaluate the benefit of fire detection cameras in the elevated wildfire risk area.

Downed conductor detection technology is an important tool to reduce ignition risk for wildfire risk mitigation. High-impedance fault situations, such as downed live conductors, are challenging to detect because they do not result in large enough fault current for traditional protection devices to sense.

The potential for detecting and isolating high-impedance faults is improved with downed conductor technology. Installation of this technology can improve public safety and reduce the risk of fire from a downed live conductor. The implementation and method of this technology depends on the controller hardware and vendor. Consumers Energy will continue to evaluate the implementation of downed conductor detection technology in the elevated wildfire risk area.

Operational Procedures

Consumers Energy has and will continue to put operational procedures in place to both mitigate ignition risk depending on the magnitude of wildfire risk at a specific time, and to respond to a wildfire event quickly and effectively to minimize harm to the public, physical structures including the electric distribution system, and the environment.

The Company will also establish various thresholds to monitor increasing wildfire risk in real-time, and operational procedures at those thresholds to mitigate an increased risk of wildfire.

The Company has already implemented a *Red Flag Warning* response and wildfire-specific emergency response plan as part of the Company's *Electric Emergency Response Plan*.

Elevated Wildfire Risk Thresholds

The situational awareness tools outlined previously will identify increasing wildfire risk in real-time. To effectively respond to any risk level appropriately, it is important to define levels or thresholds of risk.

Thresholds of wildfire risk used by other utilities include:

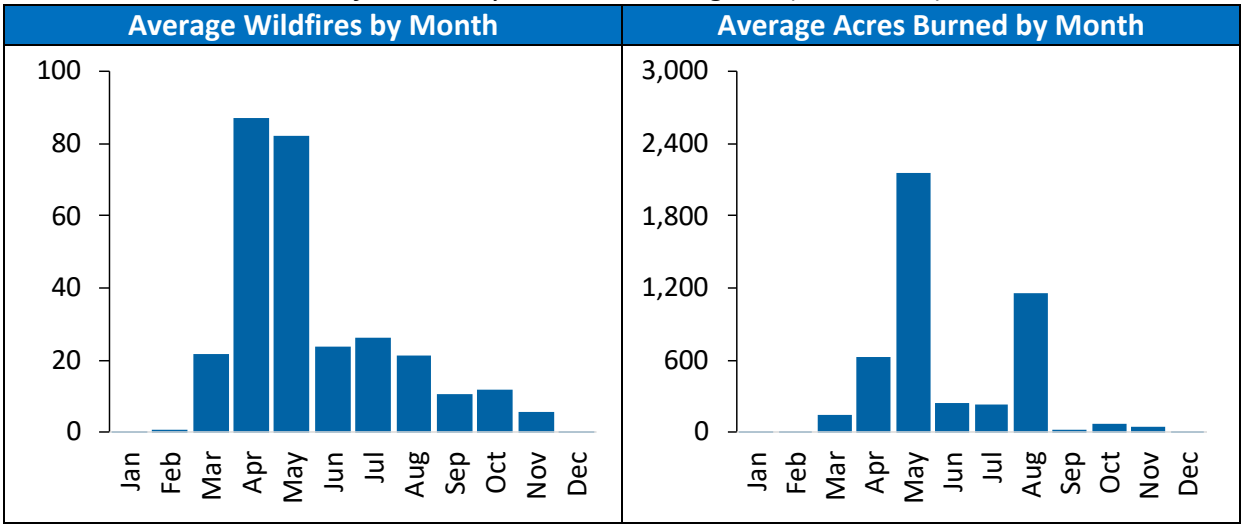
- Wildfire risk area: Designated by a third-party such as FEMA or proprietary analysis
- Wildfire season: Designated by third-party state agency or proprietary historical analysis
- Red Flag Warnings: Issued by the National Weather Service
- Unique thresholds: Based on a combination of weather conditions such as temperature, wind speed, and humidity as well as ignition risk measures like level of fuel moisture

To determine the elevated wildfire risk thresholds, the Company analyzes historical wildfire data and aligns with stakeholders to understand when step changes in risk occur.

As described in the *Risk Assessment and Mapping* section above, wildfires are most likely to occur in March through August, based on historical Red Flag Warnings and wildfire frequency. This is further supported by the cumulative acres burned per month historically as shown in Figure 14.

Figure 14

Wildfire Data by Month in Michigan[17] (2012-2024)



Operational Procedures to Mitigate Wildfire Risk

[17] Michigan Department of Natural Resources Fire Report Dashboard

There are several increasingly impactful operational procedures the utility industry is using to mitigate wildfire risk, including responding to Red Flag Warnings, modifying field operations, adjusting recloser settings, and implementing public safety power shutoff ("PSPS") events.

The Company has developed procedures for these mitigation activities to ensure that when they are employed, they will maximize wildfire risk mitigation and minimize impact to customer experience and reliability.

Red Flag Warning Response. The Company has established a Red Flag Warning response plan that incorporates monitoring potential and actual weather conditions, and initiates wildfire mitigation actions on circuits identified to have higher wildfire risk.

Red Flag Warning conditions are monitored by senior Control Center staff who are on-shift 24 hours a day, 7 days a week. Upon notification of a Red Flag Warning in areas of the state where higher wildfire risk circuits exist, the response plan is initiated with the target to put mitigation actions in place for the duration of the Red Flag Warning event. Mitigating actions include:

- Applying the Hot Line Tag function to substation reclosers to make fault condition device tripping schemes more sensitive and to clear faults more quickly
- Blocking Automatic Transfer Reclose loop schemes from operating automatically and transferring power from adjacent circuits
- Stopping hot work on energized lines on the identified circuits
- Staging field personnel at substations and LVD line sections to respond to outages and hazards
- Initiating Public Safety Power Shutoff (PSPS) in only the most extreme wildfire conditions

Field Operations. As the wildfire risk increases, many utilities modify their field operating procedures to reduce the risk of ignition from utility infrastructure or operations. Modifications include changes to requirements for:

- Open fire/burning
- Presence and use of firefighting tools
- Smoking
- Fire extinguishing
- Off-road vehicle travel
- Off-road equipment use
- Scheduled customer work or construction
- Timing of work
- Worksite preparation
- Hot work
- Line testing
- Blasting, grinding, and welding

- Line clearing activities

Since we released the 2024-2028 Plan, the Company has implemented field operations standards during Red Flag Warnings in elevated wildfire risk areas.

- Operations personnel will be placed and assigned to areas identified as elevated risk.
- Any risk identified will be discussed with Electric Operations Supervisor to determine urgency of repair.
- Types of field operations work permitted during elevated risk.

Primary outages may be restored after all primary has been inspected via stepped restoration.

If Operations responds to an emergent job that is involved in a fire, there are steps to follow, including:

1. Make the scene safe.
2. Request fire department response to ensure risk of re-ignition is mitigated.
3. Contact Electric Operations Supervisor and escalate to Senior Manager or On-Call Incident Commander.

Some aspects of the Company's standard operating procedures inherently take wildfire risk into account, like line clearing activities. The *Forestry Line Clearing Program* at Consumers Energy uses experienced line clearing vendors that have their own tactics for wildfire risk mitigation.

Some of these tactics include:

- Employees must be aware of the *Fire Danger Index* at the beginning of each workday.
- Employees complete standard fire prevention awareness and training, including the proper use of fire extinguishing equipment.
- Employees inspect fire extinguishing equipment regularly and repair or replace the equipment as needed.
- A designated individual is required to be assigned to fire watch duty when the fire danger level is high, very high, or extreme, and shall observe and monitor the work site for smoldering.
- Employees are informed of the proper actions to take in the event of a fire. This includes, but is not limited to, notification and evacuation procedures. It is stressed that at no time does the task of fighting fire supersede an employee's primary duties of ensuring their own personal safety and the safety of others. It is required to report the incident to the proper authority and ensure personal accountability for self and subordinates at the jobsite, in accordance with company and client policy.

Standard operating procedures may change as Consumers Energy evaluates and implements wildfire risk mitigation standards for field work being done by internal and contracted employees.

Recloser Settings. *Recloser settings* refer to the operational sequence and sensitivity of reclosers on the distribution system.

Reclosers open when a fault occurs and then will reclose, based on the operation sequence settings. Once a recloser opens, the line is de-energized until it closes again. Recloser operation sequence settings can be adjusted to change the response time characteristics for a fault and the number of reclose attempts.

Since most distribution faults are temporary, reclosers generally improve customer reliability by clearing faults without a sustained outage. However, upon the initial fault or if the fault is still present when the device recloses, there is a possibility sparks or arcing may occur, presenting ignition risk. To limit this ignition risk, reclosers can be set to "lock out" (remain open) upon a single trip event, until the line can be visually inspected.

Fast trip settings can also have a wildfire risk mitigation benefit. Enabling fast curve settings will cause the device to trip faster when a fault occurs, reducing the amount of energy released into a fault.

Fast trip settings can reduce ignition risk, but such settings will be detrimental to reliability due to manual circuit inspections before manually reclosing when in use.

Setting automatic reclosing to lock out upon a single trip event or enabling fast trip settings will reduce wildfire risk during elevated wildfire risk conditions by reducing ignition risk. However, it is important to note that increasing the sensitivity of recloser settings in this way results in more interruptions for customers who will require service restoration. Line sensor deployment and subsequent utilization are important in helping to identify fault locations when fast trip settings are enabled.

As part of the Company's Red Flag Warning response substation reclosers are set to Hot Line Tag ("HLT") mode during qualifying wildfire conditions. HLT operates in a one-shot mode tripping all phases as quickly as possible when a fault is detected. This configuration provides maximum protection by bypassing the standard protection scheme and prevents the recloser from being reclosed while HLT is enabled.

Experience with HLT settings revealed that substation reclosers have limited reach and may not be able to detect faults at the end of some circuits, leaving those portions of the line without the extremely fast tripping provided by the HLT modification. Consumers Energy is working to enhance the protection plan under the *Red Flag Warning* response to address this limitation.

In August 2024, an operational alert from the Electric Power Research Institute (EPRI) highlighted risks in wildfire-prone areas associated with compact single-phase reclosers, particularly regarding energized downed conductors[18].

- Compact single-phase reclosers can unintentionally re-energize downed conductors under certain conditions, increasing public safety risks.
- Furthermore, smaller or aging conductors are more vulnerable to failure during fault events, which can result in energized downed lines.

[18] EPRI - Wildfire Protection Strategies for Overhead Bare Wire Power Systems, August 2024

Consumers Energy is also evaluating different wildfire protection strategies recommended by EPRI, such as *relatively fast* clearing times compared to *extremely fast* clearing times. Relatively fast clearing times will still clear as fast as possible while maintaining some level of coordination with other protective devices on the circuit. Having this level of coordination will allow for faster fault locating and dispatching.

Consumers Energy will continue to incorporate new information and industry learnings, like those outlined by EPRI, into its ongoing efforts to refine its protection strategy to ensure both safety and reliability.

Utilities in the Western United States have employed modified recloser settings to mitigate increasing wildfire risk, as well as reduce the need to implement PSPS events. They continue to test and analyze the best settings for different combinations of weather conditions, fuel availability, and electric distribution system considerations to optimize for both wildfire risk mitigation and customer reliability.

Consumers Energy currently has automatic reclosers located at many substations in its electric service territory. The Company has the ability to modify recloser settings remotely, where automatic reclosers exist, in response to wildfire risk through the Supervisory Control and Data Acquisition ("SCADA") system at the substation level.

Consumers Energy Control Centers use SCADA to communicate with and control devices on the electric distribution system.

This capability allows remote de-energization of a substation and all distribution lines connected to the substation. Reclosers are also installed on distribution lines but they are not all electronic reclosers. Only electronic reclosers have SCADA capability. The Company is evaluating adding SCADA functionality to existing LVD line reclosers and ensuring future line reclosers are SCADA ready.

The Company is currently evaluating several recloser types to install that will add to SCADA functionality on LVD distribution lines. Adding SCADA capability to LVD distribution lines increases sectionalization of distribution lines, minimizing the impact of an outage and decreasing the need for crews to manually adjust reclosers not connected to SCADA. Remote control and engineering access will be crucial to send the recloser settings change during high wildfire risk conditions in a practical amount of time.

The Company standards for adding new communicating reclosers is being modified and will be available in 2025. These standards will be used to upgrade existing recloser sites to allow remote setting changes at targeted sites within the relatively high wildfire risk areas. Modifying the standards will result in an increase in outages and the Company will adjust service restoration procedures accordingly to combat any reliability impact.

Public Safety Power Shutoff. PSPS refers to the total de-energization of sections of the distribution system during extreme wildfire conditions. This de-energization has the potential to remove power from thousands of customers as a pre-emptive wildfire risk mitigation effort. It is an extreme action that should only be undertaken after very careful consideration of the threat and impact of a wildfire on life and property.

While many of the utilities in the Western United States have deployed this tactic in recent years, their current focus is on reducing the need for this tool by mitigating wildfire risk in other ways, including refining their approach to adjusting system settings (e.g., recloser settings) to maximize wildfire risk mitigation and reliability.

- The Company has the ability to de-energize lines remotely where SCADA is present and manually as needed. There are procedures in place to proactively de-energize portions of the system for extreme load scenarios, but these measures are rarely necessary. At this time, the Company has not established a wildfire risk-related threshold to implement PSPS.
- Effectively implementing a PSPS event requires significant stakeholder engagement prior to and during an event. An education initiative would be needed to ensure the public understands why a PSPS may be needed and what to do to prepare for the possibility.
- Notifications and associated procedures would also be required for customers, emergency personnel, and other state and community governments and agencies before, during, and throughout restoration efforts from a PSPS event.

The Company is currently developing a PSPS procedure with completion expected later in the second quarter of 2025. The PSPS procedure turns off power in specific areas when wildfire risk is high to prevent spark risk from the electric system. While PSPS can be very effective at mitigating wildfire risk, it can also negatively impact customers who depend on the Company to deliver reliable power. Therefore, careful consideration and analysis of all aspects of implementation are required. This procedure will be a last resort and only used in extreme wildfire weather conditions.

Emergency Response

Emergency response refers to actions the Company takes to respond to a wildfire event. In any incident, response activities are prioritized based on:

1. Life safety
2. Incident stabilization
3. Property/Environmental preservation

Outlined in the *Wildfire Hazard Specific Annex* is a recommended structure of command, staffing, suggested incident objectives, and actions that must be taken to return the Company to normal operations. This includes internal and external notifications, information assistance, and collaboration with relevant local agencies.

This annex is housed within the Company's overarching *Electric Emergency Response Plan*. The annex was developed by the Emergency Management Program in coordination with Electric Operations to align with the FEMA's National Incident Management System ("NIMS") and the Company' Incident Command System ("ICS").

NIMS guides all levels of governmental and non-governmental organizations and the private sector to work together to prevent, protect against, mitigate, respond to, and recover from incidents. The structure of the ICS activation is similar to the storm response operations that the Company described in the Reliability Roadmap.

System Hardening for Wildfires

System hardening for wildfires is improving, modernizing, and hardening the distribution system with wildfire risk mitigation as a prioritized concern.

Based on industry research and benchmarking, system hardening best practices for wildfire risk mitigation include:

- Further sectionalizing the distribution system
- Fractionalization of substations and circuits
- Enhancing pole inspections and remediations
- Undergrounding overhead lines
- Replacing traditional expulsion fuses
- Installing covered conductor
- Constructing microgrids

Consumers Energy is investing in a layered approach to strengthen overhead lines and harden the distribution system by undergrounding overhead lines, installing covered conductor, and adding or replacing protective line devices within the elevated wildfire risk area. The goal of this layered approach is to help mitigate contact with tree limbs and other foreign objects that may lead to wildfire ignition, and to minimize the impact this contact may have on the distribution system and the customers we serve.

Consumers Energy will first prioritize investment in the Relatively High wildfire risk areas, and then phase in investments in the Relatively Moderate wildfire risk areas over the next several years. This investment approach enables the Company to evolve and adjust as more is understood about wildfire risk within Michigan, and the utility industry as a whole.

The Company will continue to evaluate additional system hardening best practices such as enhancing pole inspections, replacements, and constructing microgrids.

Undergrounding

Undergrounding overhead conductor has been identified by multiple utilities as the best practice for wildfire risk mitigation.

By undergrounding overhead conductor, the largest contributor to wildfire ignition from a powerline, foreign objects touching overhead conductor, is eliminated and Consumers Energy expects to see fewer faults and ignitions in those areas.

Of the 4,977 miles of overhead conductor in the elevated wildfire risk areas, Consumers Energy has identified 2,058 miles as candidates for undergrounding.

To identify undergrounding candidates, the Company used criteria similar to that used for the Undergrounding Pilot that was approved on March 1, 2024, in its Electric Rate Case, Case No. U-21389. These criteria include single-phase sections of the system:

- Serving between 10 and 100 customers

- Operating at one of the three standard voltages

To identify undergrounding candidates to mitigate wildfire risk, the analysis did not take into account a history of long duration outages as proposed in the Undergrounding Pilot because duration of outages do not necessarily correlate to ignition risk.

Consumers Energy will begin undergrounding approximately 10 miles per year starting in 2027 for the purpose of wildfire risk mitigation. Line miles in the Relatively High wildfire risk areas will be prioritized. The estimated cost of this undergrounding program is $4 million per year.

Additional miles may also be undergrounded each year in wildfire risk areas through the resiliency efforts outlined in the Company's Electric Rate Case. These projects would be specifically chosen for resiliency, but provide benefits to both resiliency and wildfire risk mitigation endeavors.

Given there are 147 miles in the Relatively High wildfire risk area and 1,911 line miles in the Relatively Moderate wildfire risk area, the Relatively High wildfire risk areas would be completed by 2041. The Relatively Moderate wildfire risk areas will be evaluated for specific projects that meet the criteria required, and will be prioritized based on individual project evaluation criteria.

Undergrounding overhead conductor requires specific resources and permits to construct. With more than 4,000 miles of overhead conductor in the elevated wildfire risk areas, the likelihood of undergrounding all within a reasonable amount of time is very low, making the layered approach (covered conductor and undergrounding) a much more feasible way to quickly mitigate wildfire risk.

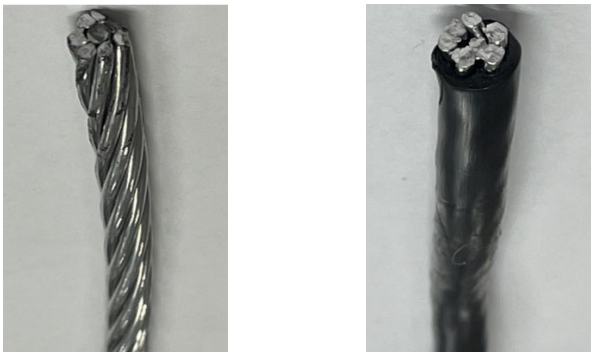
Covered Conductor

Covered conductor is a conductor cable design that includes a polymer sheath on the external portion of the wire to protect against incidental contact with trees and other vegetation.

Figure 15 is an example of covered conductor next to bare or traditional conductor. Covered conductor has multiple advantages over traditional conductor, and is typically used to increase system reliability and mitigate the probability of ignition from vegetation caused arcing.

Figure 15

Bare versus Covered Conductor

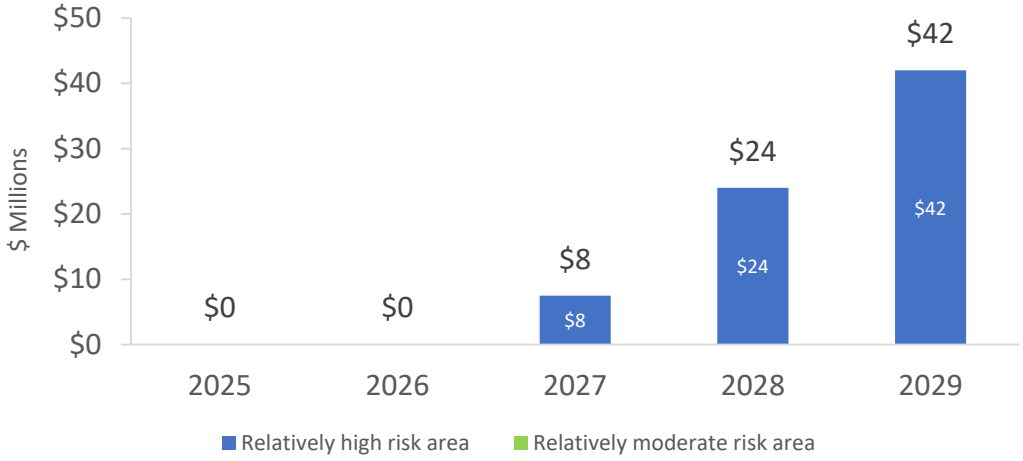


After accounting for undergrounding, covered conductor may be installed on nearly 3,000 line miles to reduce wildfire risk—196 line miles in the Relatively High wildfire risk area and 2,723 line miles in the Relatively Moderate wildfire risk area.

Consumers Energy will prioritize the Relatively High wildfire risk areas by installing 15 miles of covered conductor in 2027, ramping up to 120 miles by 2030, allowing the Relatively High wildfire risk area to be completed by 2034, and the Relatively Moderate wildfire risk area to be completed thereafter. The 5-year investment plan for covered conductor is shown in Figure 16.

Figure 16

Covered Conductor Capital Investment Plan



Protective Line Devices

Consumers Energy has a large distribution network providing service to the majority of Michigan's lower peninsula. This large network can experience faults on the system caused by a wide range of factors.

When faults on the distribution system occur, the distribution system primarily relies on sectionalizing devices to protect the system. Automatic sectionalizing devices including fuses, sectionalizers, and reclosers maintain electric service reliability by isolating faulted sections of the system.

Manual sectionalizing devices including disconnect and load-break switches provide a convenient means of changing system connections.

Fuses. The majority of the fuses currently on the distribution system are *expulsion fuses* that are designed to operate by creating an expulsion within the fuse resulting in the fuse isolating the fault, see Figure 17.

When an expulsion occurs, the molten material within the fuse is discharged out of the fuse casing through a venting system in the bottom of the fuse cylinder and could ignite nearby fuel sources.

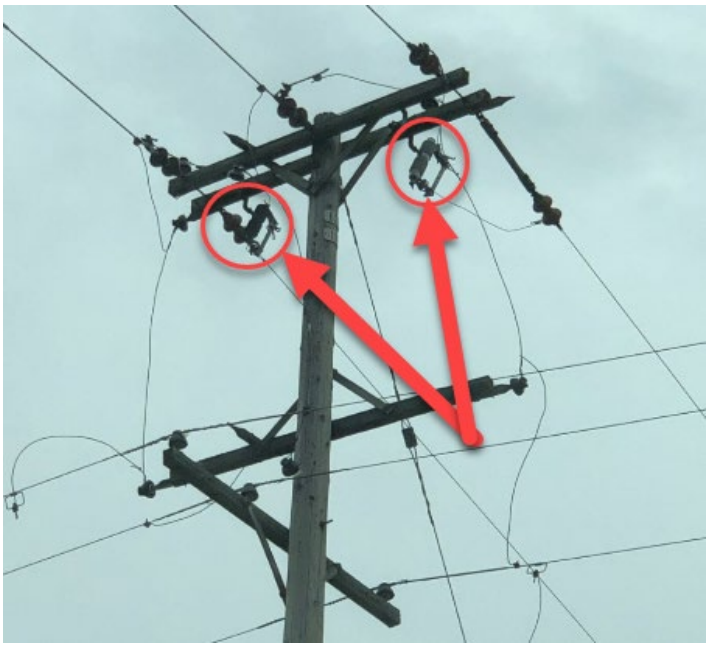
Due to this ignition risk, CAL FIRE and other wildfire protection organizations in the western United States have safety requirements for the use of expulsion fuses, and utilities in the western United States are actively replacing expulsion fuses with non-expulsion fuses.[19]

To best mitigate the possibility of ignition resulting from these devices, Consumers Energy is evaluating their replacement within the elevated wildfire risk areas. This includes benchmarking other utilities and fuse options to identify the most effective non-expulsion alternatives.

Among these options, Consumers Energy is exploring full-range current-limiting fuses, such as the ELF Fuse by Eaton Cooper, which fits into a standard cutout. These devices provide a safer alternative for wildfire-prone areas and align with best practices highlighted by EPRI for reducing risks associated with expulsion events and potential ignition hazards.

Figure 17:

Lateral Fuse Installation (2-phase)



Reclosers. Reclosers are single-phase or three-phase interruptive devices installed in substations or on primary lines for circuit sectionalizing. As discussed in the Operational Procedures section, electronic recloser settings can be adjusted to mitigate ignition risk in elevated wildfire risk conditions.

Adding electronic reclosers, as shown in Figure 18 below, to LVD distribution lines in the elevated wildfire risk area will allow the Company to only adjust settings for a portion of a circuit instead of the entire circuit with a substation recloser.

[19] California Power Line Fire Prevention Field Guide

Figure 18

Recloser Installation



Additionally, the Company is evaluating compact reclosers, including the ABB Eagle and S&C TripSaver II as shown in Figure 19.

Consumers Energy is closely considering insights from EPRI to ensure reclosers are configured to avoid the risks they highlight, such as increased hazards when deployed on smaller or aging conductors or when multiple trip/reclose cycles are allowed.

By refining recloser settings, thoroughly assessing deployment locations, and evaluating line conditions, Consumers Energy is ensuring these devices are strategically implemented to enhance safety and reliability while mitigating potential risks.

Figure 19

S&C TripSaver II[20]

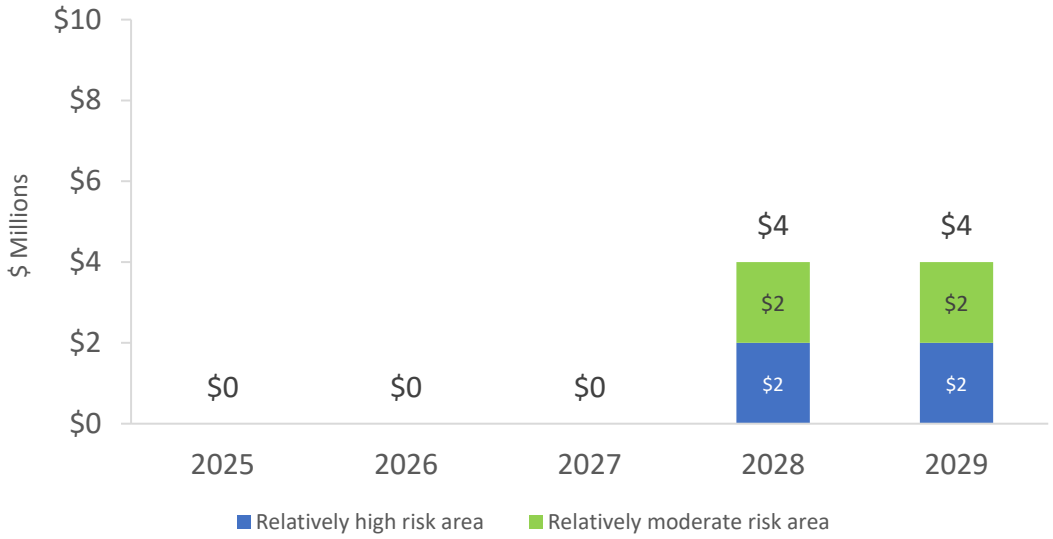


[20] https://www.sandc.com/en/products--services/?c=204

The 5-year investment plan for protective line devices including fuses and reclosers is shown below in Figure 20.

Figure 20

Protective Line Devices Capital Investment Plan



Voltage Conversions

The Company's three standard voltages, 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV, comprise the majority of LVD overhead primary line miles in the elevated wildfire risk area. However, there are some line miles configured as Delta systems that are less safe to operate compared to a grounded wye system.

As described more fully in the Reliability Roadmap, by converting non-standard components to one of the three standard voltages, the Company will mitigate the safety risk from ungrounded wires and increase operational flexibility by expanding the ability to transfer loads to reduce outage times. This will support wildfire risk mitigation by preparing the circuits for more controllability to execute wildfire risk mitigation operational procedures, and reduce ignition risk from ungrounded wires.

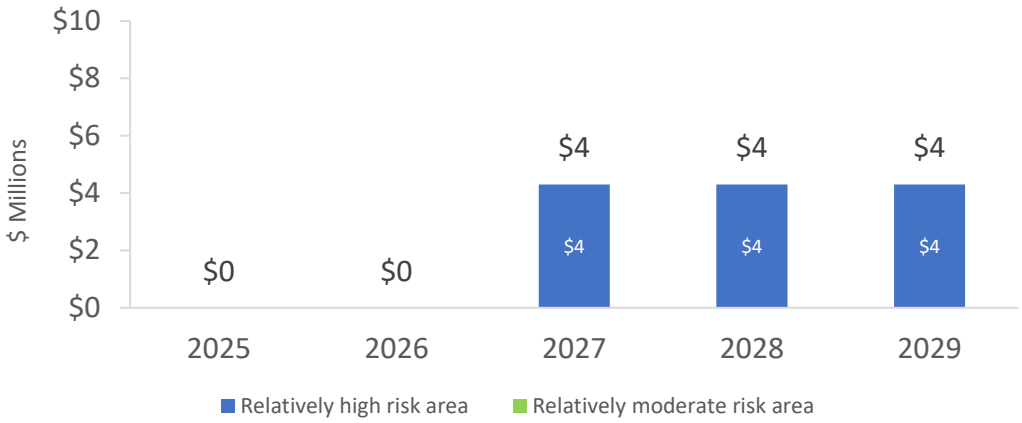
There are 722 lines miles of non-standard voltages on circuits that intersect the elevated wildfire risk area—106 line miles in the Relatively High wildfire risk areas, and 616 line miles in the Relatively Moderate wildfire risk areas.

Consumers Energy will begin converting 25 miles of non-standard voltages per year starting in 2027 for the purpose of wildfire risk mitigation. Line miles in the Relatively High wildfire risk area will be prioritized, thus enabling these wildfire risk areas to be completed by 2031, and the Relatively Moderate wildfire risk areas to be completed thereafter.

The 5-year investment plan for voltage conversions is shown below in Figure 21.

Figure 21

Voltage Conversions Capital Investment Plan



Opportunities to Evaluate

The Company continues to evaluate additional ways to use system hardening to mitigate wildfire risk by benchmarking with other utilities, researching technology, and collaborating with EEI and EPRI to identify new technologies and best practices.

While Consumers Energy will refine plans for undergrounding, covered conductor, and protective line devices based on learnings from initial investments, the Company is also evaluating increasing pole inspections and replacements and microgrids in the elevated wildfire risk area.

Wooden utility poles have been in consistent use within Michigan for decades, and it is estimated that there are more than 2 million throughout the state. These poles support the distribution network of electric utilities as well as telephone companies and Internet providers.

Inspecting and replacing poles as needed is a priority for Consumers Energy. The Company has a plan to inspect LVD poles on a 12-year cycle to identify and replace all rejected poles that do not meet *National Electric Safety Code* ("NESC") standards. This requires inspecting 125,000 primary and secondary poles each year, and based on the historical 10% rejection rate, replacing approximately 12,500 poles a year.

With the current inspection and replacement program in place, Consumers Energy will continue to evaluate whether an enhanced wildfire specific pole inspection and replacement plan should be implemented in the elevated wildfire risk areas.

Ductile iron poles could be a replacement for the standard wooden poles currently used, and are being evaluated as a potential option for mitigating wildfires. The benefit of iron poles is the durability, life span, and reduction in potential fuel for a wildfire.

Fractionalization is **the practice of segmenting circuits into smaller sections with fewer customers to reduce the number of customers impacted by single contingency outages** and customer exposure to outages.

As the distribution system has been expanded over many years to meet the requirements of connecting new customers, there are a subset of circuits with disproportionately high customer counts and overhead line exposure, resulting in challenges due to the underlying system configuration. Limiting the number of customers impacted by any single outage is growing in importance as increasing recloser sensitivities to mitigate wildfire risk will likely result in more outages.

Microgrids provide power to critical facilities and infrastructure when a line is de-energized or there is some other emergency that caused electricity not to be available. **Microgrids are self-contained grids which can connect or disconnect from the larger grid and still provide power usually from a battery or renewable power source.** Other utilities are using microgrids to reduce wildfire ignition risk as well as provide back-up power to strategic locations during times of emergency or outage.

A microgrid would enable power to continue to be used in areas that may have been isolated by surrounding wildfires, diminishing the effects of power outages, and allowing emergency responders to continue to use facilities that might be unavailable during a power outage.

Microgrid solutions to mitigate wildfire risk include remote microgrids, grid-connected microgrids, and microgrid incentives.

- *Remote microgrids* are not connected to the utility electric distribution system and operate in isolation.
- *Grid-connected microgrids* are connected to the utility electric distribution system, but they may be separated from the distribution system as needed.
- *Microgrid incentives* are to fund third-party owned microgrids.

Line Clearing

Line Clearing Program for Wildfire Risk Mitigation

Trees are one of the greatest causes of interruptions to electric service to customers on the LVD system, contributing 43.4% of all-weather outages and 37.9% of all non-Major Event Day ("MED") outages[21].

The Company clears vegetation within a 30-foot-wide right-of-way ("ROW") for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing, and to maintain accessibility along the ROW for maintenance and repair of the line.

The Company has been defining plans in its electric rate cases starting in 2020, and in the Electric Distribution Infrastructure and Investment Plans/Reliability Roadmap starting in 2021, to achieve and maintain a 7-year effective clearing cycle for its LVD system.

[21] Percent of customers interrupted by unplanned outages in 2024 with cause code of Trees or Trees - Outside ROW.

In Case No. U-21585, the Company proposed moving LVD circuits that intersect with relatively high wildfire risk areas to a 5-year clearing cycle and later expand to LVD circuits that intersect with relatively moderate wildfire risk areas.

The Company is proposing an enhanced line clearing strategy for the entirety of its LVD system: to ramp-up to a 5-year clearing cycle and perform more aggressive line clearing on targeted 3-phase primary lines. The proposed timeline to achieve the shortened line clearing cycle and scope of more aggressive line clearing is targeted by the end of the 2030-2031 test period, which is a similar timeline that the Company proposed in rate cases starting in 2020 to achieve its previous 7-year effective cycle strategy.

The proposed strategy encompasses the LVD system and therefore includes circuits intersecting with wildfire risk. While the Company is proposing to achieve the reduced cycle strategy by the end of the 2030-2031 test period for all LVD circuits, the Company is proposing a more aggressive timeline in wildfire risk areas. This includes:

- Achieving the 5-year cycle for circuits in the relatively high wildfire risk area by year-end 2026; and
- Achieving the 5-year cycle for circuits in the relatively moderate wildfire risk area by year-end 2028.

There are 133 circuits that intersect the elevated wildfire risk areas; 17 of these circuits intersect with areas identified as relatively high risk.

Reducing the line clearing cycle length to five years for circuits in the elevated wildfire risk areas decreases the chance of tree-conductor contact, thereby reducing the potential of a spark igniting a wildfire. The expense required to achieve the enhanced line clearing strategy is outlined in the Reliability Roadmap.

The Company is proposing to continue the small pilot to capture Light Detection and Ranging ("LiDAR") imagery for approximately 850 LVD primary miles on circuits that intersect with the relatively high wildfire risk area. The purpose of this pilot is to inform and support the execution strategy of proposed line clearing tactics described above. Figure 2 above includes the estimated annual O&M cost for LiDAR collection and processing. In Case No. U-21585, the Company outlined $0.319 million for LiDAR in this area, and it is updating this projected annual expense to $0.500 million after gaining insights through conducting a request for information (RFI) with LiDAR vendors.

Opportunities to Evaluate

The Company will continue to evaluate additional ways to adjust line clearing practices to mitigate wildfire risk by benchmarking with peer utilities and collaborating with organizations such as the Electric Power Research Institute (EPRI) to identify new technologies and best practices for wildfire risk mitigation. One opportunity for further evaluation is an expanded scope of hazard tree removal in the elevated risk areas.

Hazard trees (dead, dying or mechanically stressed trees) within 20 feet of the edge of the ROW are removed when the property owner does not object. Currently, hazard trees are identified and removed as part of the standard clearing cycle process in the *Line Clearing Program*.

In elevated wildfire risk areas, wildfire risk could be further mitigated by expanding the scope of hazard tree removal through either frequency or distance from pole centerline.

- Mid-cycle hazard tree removal mitigation would identify hazard trees during off-cycle times and remove them; this will help mitigate the risk of hazard trees falling on lines in-between cycle clearing.
- Expanding the distance from centerline hazard trees are identified and removed would help mitigate the risk of hazard trees further away falling on lines.

Figure 22 below illustrates the risk of trees outside of the standard 30' ROW corridor.

Figure 22

Out of ROW Tree Failure on LVD Three Phase



The Company is proposing a focus on achieving its enhanced line clearing program strategy by the end of the 2030-2031 test period, as outlined in the Reliability Roadmap, which includes reduced cycles across the electric service territory and a scope of more aggressive line clearing, before adding additional line clearing tactics such as mid-cycle hazard tree removal.

Stakeholder Engagement

Industry. Through benchmarking with utilities located in the Eastern, Southeastern, Midwest, Mountain West, and Pacific West, Consumers Energy identified best practices for wildfire risk mitigation. These relationships will be leveraged as the Company continues to build out and mature this wildfire risk mitigation plan. Consumers Energy is also engaged with industry groups including EEI and EPRI, which provides knowledge sharing opportunities through working groups and summits.

Agencies. Communication and coordination with local and state emergency agencies and first responders is essential to the success of wildfire risk mitigation. Consumers Energy coordinates with these agencies as part of the Company's standard emergency response activities and will broaden that engagement as wildfire risk-specific mitigation activities are operationalized.

There may be opportunities to engage with local and state agencies on public education and awareness, wildfire risk mitigation planning, wildfire risk mitigation activities, wildfire emergency preparedness, and wildfire emergency response.

Public. The Company will use existing corporate communications and community affairs channels to engage the public on the wildfire risk mitigation activities and investments in this plan. As the plan matures, additional engagement will be considered to increase education and awareness around times of elevated wildfire risk or if a PSPS plan is developed.

Conclusion

This wildfire risk mitigation plan is designed to protect public safety, physical structures, the environment, and the electric distribution system.

By proactively identifying risks, implementing mitigation measures, maintaining readiness, and collaborating with relevant state and local agencies, Consumers Energy can reduce the impact of wildfires on our operations and maintain a resilient electrical grid for the state of Michigan.

As part of this approach, the Company will continue to determine best practices and gain additional knowledge around the cost and effectiveness of the wildfire risk mitigation tactics implemented which are outlined in this plan.

Consumers Energy will continue to evaluate investment plans based on skills and efficiencies learned during the test year and may propose a more aggressive future workplan to mitigate wildfire risk.

Regular reviews and updates to this plan will be made to ensure it remains consistent with industry and government recommendations and standards which are still evolving.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Advanced Metering Infrastructure Metrics and Elements

Case No.: U-21870
Exhibit No.: A-133 (MPK-23)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No.	(a) Metric	(b) Value	(c) Result	(d) Notes
1	**Consecutive estimates**	**Efficiencies, Cost Savings**		
2	2024 AMI electric meter read rate		99.80%	
3	Consecutive estimates as of December 31, 2024		197	Customers with more than 2 electric consecutive estimates
4	**Demand Response (DR)**	**Cost Savings**		**Reduces capacity needs**
5	Air Conditioning Peak Cycling (ACPC) MW enrollments		55.0	As of December 31, 2024
6	Peak Time of Use (TOU) MW enrollments		37.4	As of December 31, 2024
7	Smart Termostat Program (STP) MW enrollments		53.9	As of December 31, 2024
8	2024 ACPC maximum MW demand reduction achieved		77.3	
9	2024 TOU maximum MW demand reduction achieved		0.0	No events completed in 2024
10	2024 STP maximum MW demand reduction achieved		84.4	
11	Summer PY2024 DR awarded as Load Modifying Resources		506.4 MW	
12	75% of PY2024 MISO Cost of New Entry (CONE)		$95,351	PY2024 CONE of $127,135/MW times 75%
13	Value of DR in Reducing Capacity Needs		$48,285,746	Line 11 times Line 12
14	**Conservation voltage reduction (CVR)**	**Cost Savings**		**Reduces capacity needs**
15	Number of CVR enabled circuits as of December 31, 2024		430	
16	Number of circuits that are planned for CVR enablement		900	Plan to enable 85 circuits per year until 900 are enabled
17	Percentage of total planned circuits enabled		48%	Line 15 divided by Line 16
18	2024 Conservation Voltage Reduction		17.6 MW	
19	75% of PY2024 MISO Cost of New Entry (CONE)		$95,351	PY2024 CONE of $127,135/MW times 75%
20	Value of CVR in Reducing Capacity Needs		$1,678,178	Line 18 times Line 19
21	**Leverage data to target reliability investments**	**Reliability**		
22	2024 System Average Interruption Duration Index (SAIDI)		154.97	Excluding major event days
23	2024 System Average Interruption Frequency Index (SAIFI)		0.877	Excluding major event days
24	Outage minutes avoided due to AMI meters			CAIDI = Customer Average Interruption Duration Index
25	2024 CAIDI excluding MEDs for AMI notification only		119	MED = Major Event Days
26	2024 CAIDI excluding MEDs for customer notification only		179	
27	2024 CAIDI excluding MEDs for AMI and customer notification		172	
28	2024 Momentary Average Interruption Frequency Index (MAIFI)		2.63	
29	**Qualitative elements**	**Varies**		
30	Support Load Flow Tool Upgrade	DER Deployment		Support automating data modeling and forecasting of grid impacts from distributed energy resources (DERs) and electric vehicles (EVs) to provide planning departments with visibility of present and future capacity constraints on the LVD system as DER and EV penetration increases
31	Assess SAIDI in Environmental Justice (EJ) communities	Reliability		Measuring SAIDI in specific EJ communities would allow the Company to better target reliability investments
32	Measure energy exported to the grid from Distributed Energy Resources (DERs)	DER Deployment		Measure energy exported to the grid from distributed generation such as solar, batteries, electric vehicles, etc. to analyze impact to the grid and better understand how to best utilize future DER deployment

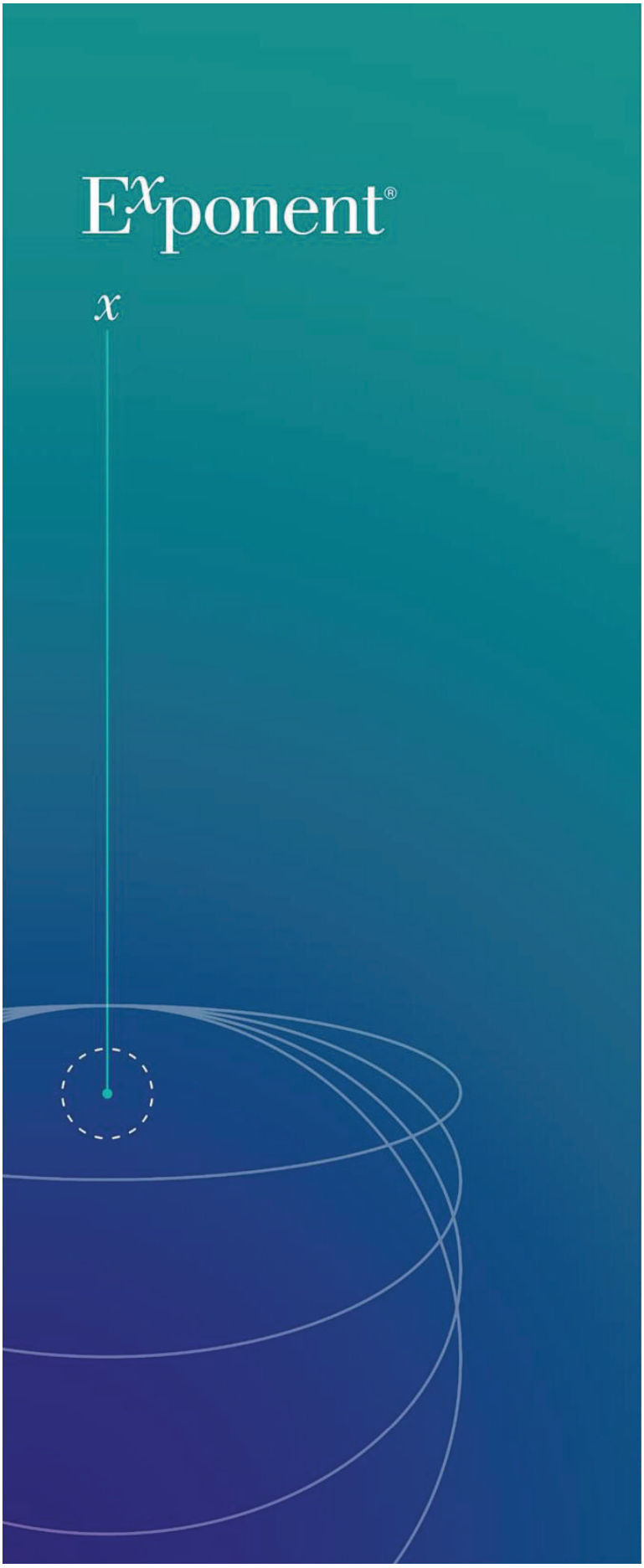
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Distribution
Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11
($000)

Case No.: U-21870
Exhibit No.: A-134 (MPK-24)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				Capital Expenditures			
Line No.	Program Description	Historic Test Year 2024 Actual	Last Rate Case Approved Spending Plan Case No. U-21585 12 mos. Ending 2/28/2026	Last Rate Case Actual Spending Case No. U-21585 12 mos. Ending 2/28/2026 [1]	Variation Percentage [1]	Location of Testimony Regarding Significant Var [1] (>10%)	Current Case Projection 12 mos. Ending 4/30/2027
1	New Business Program	308,029	267,333	n/a	n/a	n/a	389,759
2	Reliability Program	219,105	396,384	n/a	n/a	n/a	697,127
3	Capacity Program	98,235	99,050	n/a	n/a	n/a	140,809
4	Demand Failures Program	222,634	206,177	n/a	n/a	n/a	185,431
5	Asset Relocation Program	63,767	51,859	n/a	n/a	n/a	100,393
6	Electric Other Program	8,669	8,389				8,542
7	Wildfire Mitigation & Vulnerable Community	-	-				30,000
8	**Total Capital**	920,439	1,029,192	-			1,552,061
9	IIJA Grant Funding & Fleet Depreciation	-	(26,139)				(22,148)
10	Total Capital net of Savings	920,439	1,003,053				1,529,913

Footnote:

[1] The projected test year in Case No. U-21585 has not transpired as of the date of this filing



Consumers Energy

Reliability Regression Analysis for Environmental Justice Communities

Exponent®

Consumers Energy

Reliability Regression Analysis for Environmental Justice Communities

Exponent Report

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Table 26. Comparison of census-tract-level disconnection rates for each year from 2020 through 2024 averaged for the 10% of census tracts with the worst reliability per each metric (the Vulnerable group) and all other census tracts within Consumers service territory (the Non-Vulnerable group). Significance is assessed at $\alpha = 0.05$. 81

Limitations

The study presented in this report is intended for use by Consumers Energy Company ("Consumers") to inform their decisions related to distributional equity of electric reliability among the various communities that they serve. While this study is informative, it is understood and agreed that responsibility for these decisions remain fully with Consumers. Proper application of this report requires recognition and understanding of the limitations of both the scope and methodology of the study. The scope of the study was limited to performing regression analysis to assess correlations between electric reliability and: (1) demographic characteristics of communities served by Consumers; and (2) physical characteristics of distribution circuits. The scope of the study also included regression analysis of correlations between residential involuntary disconnections for non-payment and demographic characteristics of communities within Consumers' service territory.

In the analysis, Exponent has relied on data and various other information provided by Consumers. We cannot verify the correctness of this input data and rely on Consumers for their accuracy.

Exponent has exercised professional skill and care ordinarily provided by professionals practicing in the same or similar locality under the same or similar circumstances in the preparation of this report, and the findings presented herein are made based on information available to Exponent as of the date of this report. This report may be supplemented to expand or modify our findings based on additional analysis or review of additional information.

Executive Summary

The state of Michigan defines environmental justice as "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income," and states that it "is critical to the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn."[1] In environmental justice contexts, there are four broad types of equity: (1) distributional equity, which relates to the distribution of benefits and burdens across all segments of a community and across generations; (2) recognitional equity, which relates to recognition of how societal structures have led to energy inequities; (3) procedural equity, which relates to the development and implementation of programs and policies; and (4) restorative equity, which relates to repairing past inequities, rectifying practices that perpetuate inequities, and holding decision-makers accountable.[2] While utility customers can be affected simultaneously by these different, overlapping types of (in)equities, the focus of the present study is the distributional equity of electric reliability among Consumers' current customers: that is, do different customers have different experiences of electric reliability?

In August 2024, the Office of the Environmental Justice Public Advocate within the Michigan Department of Environment, Great Lakes, and Energy published the Michigan Environmental Justice Mapping and Screening Tool ("MiEJScreen").[3] MiEJScreen aims to identify Michigan communities that may be disproportionately impacted by environmental hazards.[4] For each 2010 Census tract in the state, MiEJScreen calculates the MiEJScreen Overall Score, which is based on the census tract's relative level of each of 26 indicators that fall into four categories: Environmental Exposures, Environmental Effects, Sensitive Populations, and Socioeconomic Factors.[5] The MiEJScreen Overall Score for a census tract ranges between 0 and 100; higher values indicate that people in that census tract experience higher pollution burden and vulnerability than people in census tracts with lower scores.

The first objective of this study was to quantify differences in the experiences of two groups of Consumers' customers: (1) those in census tracts with MiEJScreen Overall Scores > 80, known as EJ communities; and (2) those in census tracts with MiEJScreen Overall Scores ≤ 80, known as non-EJ communities. EJ communities in Consumers' service territory comprise 64 census tracts in seven cities and are considered more burdened and more vulnerable than non-EJ communities. We used statistical techniques including regression analysis to assess whether evidence exists that EJ communities experience worse electric reliability than non-EJ

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1 Office of the Environmental Justice Public Advocate and Michigan Department of Environment, Great Lakes, and Energy. (2024). MiEJScreen1.0: Michigan Environmental Justice Mapping and Screening Tool Technical Report. https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/Report-2024-07-MiEJScreen-Technical.pdf. p4.

2 *Id*.

3 Michigan Department of Environment, Great Lakes, and Energy. "State launches MiEJScreen Version 1.0 to illuminate environmental, health and socioeconomic conditions in communities." August 6, 2024. https://www.michigan.gov/egle/newsroom/mi-environment/2024/08/06/state-launches-miejscreen-version-1

4 MiEJScreen1.0: Michigan Environmental Justice Mapping and Screening Tool Technical Report, p6.

5 *Ibid*, p11.

communities. The results of this analysis suggest that EJ communities tend to experience better average reliability than non-EJ communities. The results of the regression analysis also indicated that increasing MiEJScreen Overall Score is statistically significant and correlated with improving reliability (when all other variables, as well as county and year factors, are held constant) in terms of various reliability measures: SAIDI including MEDs; SAIFI including MEDs; CAIDI including or excluding MEDs; CELID-5 and CELID-24; CEMI-4, -5, and -7; Unique Customers with an Interruption; and Total Customer Interruptions.

The second objective of this study was to understand whether groups of customers that may be disadvantaged or reasonably expected to be more vulnerable to disruptions in electric service experience worse electric reliability than other customers in Consumers' service territory. We found that Urban census tracts tend to have better average reliability than Rural census tracts; that Low-Income census tracts tend to have better reliability than High-Income census tracts; and that High-Percent-Minority-Percentile census tracts tend to have better reliability than Low-Percent-Minority Percentile census tracts. Census-tract-level regression analyses indicate that more vulnerable communities tend to have better reliability than less vulnerable ones. As in the analysis of EJ and non-EJ communities, we also used regression analysis to assess whether evidence exists of tract-level disparities in electric reliability across different demographic characteristics like income, race, and location. We found that when controls are included for Poverty, Median Household Income in the past 12 months, Population Density, Percent Unemployed, and Housing Burden, a statistically significant correlation between Percent Minority Percentile and improving reliability is observed for SAIDI excluding and including MEDs; SAIFI excluding and including MEDs; and CEMI-4, -5, and -7. We also found that when controls are included for MiEJScreen Overall Score, Median Household Income in the past 12 months, Population Density, and Housing Burden, increasing Poverty and increasing Percent Unemployed have statistically significant correlations with worsening reliability, in terms of SAIDI excluding and including MEDs as well as SAIFI excluding and including MEDs. Census tracts with higher poverty and unemployment rates tend to have longer and more frequent outages when all other variables, including MiEJScreen Overall Score, as well as county and year effects, are held constant.

The third objective of this study was to assess how different characteristics of distribution circuits relate to circuit reliability. Among the characteristics included in the analysis were physical attributes of the circuits themselves, such as voltage, the length of primary line miles, the number of customers per primary line mile, the length of open-wire secondary miles, mean canopy cover, and how long since vegetation near the circuit was last trimmed. While the impact of individual physical circuit attributes on circuit reliability is generally well understood, we also assessed whether meaningful correlations existed between circuits' reliability and demographic characteristics of the communities they serve. For example, we classified circuits as serving EJ census tracts, Urban census tracts, High-Percent-Minority-Percentile census tracts, and Low-Income census tracts. We then used regression analysis to explore associations between each of these classifications and circuit reliability, and to understand whether there was evidence of disparities in the reliability of circuits serving areas with disadvantaged or more vulnerable populations. Feeders serving EJ census tracts were found to have a statistically significant positive correlation with the frequency of outages: a feeder serving an EJ census tract is associated with an increase of approximately 0.1 interruptions per customer per year in SAIFI excluding MEDs compared to feeders not serving EJ census tracts when all other variables

(comprising feeder characteristics as well as demographic characteristics of the census tracts served by feeders) are held constant. Since the average SAIFI excluding MEDs of all feeders in Consumers' system is approximately 1.0 interruptions per customer per year, this result is practically significant, representing a 10% increase compared to that average. Similarly, a feeder serving an EJ census tract is associated with an increase of 0.13 interruptions per customer per year in SAIFI including MEDs compared to feeders not serving EJ census tracts when all other variables are held constant. Since the average SAIFI including MEDs of all feeders is approximately 1.4 interruptions per customer per year, this result is also practically significant, representing an approximately 9% increase relative to that average. Whether a feeder serves Urban, Low-Income, or High-Minority-Percentile census tracts was not found to have statistically significant correlations with SAIFI. The results of the feeder-level reliability regression analysis – namely, that feeders serving EJ census tracts tend to have more frequent outages then those serving only Non-EJ census tracts, when all other variables are held constant – contrast with those of the census-tract-level reliability regression analysis, which suggest that increasing MiEJScreen Overall Score is correlated with less frequent outages. These contrasting results may reflect the process by which feeders were classified as serving EJ census tracts – namely, that a feeder with any overlap with an EJ census tract was classified as serving an EJ census tract – and may warrant further study.

The fourth and final aim of this study was to assess whether evidence exists of disparities in the rate of residential involuntary disconnections for non-payment among different communities served by Consumers. We used regression analysis to explore associations between communities' demographic characteristics and their disconnection rates. Because disconnection for non-payment does not physically depend on characteristics of the electric grid, we did not include circuit characteristics in this analysis. The results of a regression analysis of disconnection rates indicate Percentage Minority Population is statistically significant and positively correlated with disconnection rate when other socioeconomic and demographic characteristics – namely, Median Home Value, Percentage Below Poverty Population, Unemployment Rate, Percentage Renters, Percentage Homes Built after 1990, and Population Density – are controlled for. When all other variables as well as county-level and year factors are held constant, a one percentage-point increase in Percentage Minority Population is associated with an increase of 1.0 disconnections per 1000 households. This result is practically significant: it represents an approximately 2% increase compared to the average annual disconnection rate (considering all census tracts within Consumers territory) of approximately 50 disconnections per 1000 households from 2021 through 2024 (a moratorium on disconnections was in place for part of 2020, resulting in a substantially lower rate of disconnections that year). It is also notable that the effect of a one percentage-point increase in Percentage Minority Population is greater than that of a one percentage-point increase in Percentage Below Poverty Population, which is also statistically significant and associated with an increase of approximately 0.6 disconnections per 1000 households.

The results of the regression analysis of residential disconnection rates indicate that disparities in Minority Population disconnection rates exist that are not explained by poverty or employment status, which we would expect to be correlated with residential disconnections due to non-payment, or by the other variables controlled for in the regression model. This finding suggests a need for further study of disconnection policies and their implementation in and impacts on different communities.

Reliability and Demographic Data

For each year from 2020 through 2024, Consumers provided annual reliability data tabulated for: (1) 2010 Census tracts within their service territory; (2) 2020 Census tracts within their service territory; and (3) circuits within their distribution system, also called "feeders." Consumers also provided annual counts of the number of residential involuntary disconnections due to non-payment, or "shutoffs", over the same period and tabulated for 2020 Census tracts. These reliability and disconnection data were used as dependent variables in the regression analyses detailed in subsequent sections of this report. We obtained demographic data from the MiEJScreen tool and from the United States Bureau of the Census ("Census Bureau"). These demographic data were used as independent variables in the regression analyses, as were feeder characteristics provided by Consumers. The following subsections detail the different datasets used in the various analyses conducted as part of the present study.

2010 Census Tract-Level Data

Reliability Data

Consumers provided annual values of 18 reliability metrics at the 2010 Census-tract level for 2020 through 2024. Values of three reliability indices were calculated both with and without Major Event Days (MEDs), i.e., days during which "the daily system SAIDI [System Average Interruption Duration Index] exceeds a threshold value."[6] While there are 1176 census tracts within Consumers' service territory, reliability data was made available for only the 1050 census tracts with highest populations; because the other 126 census tracts have 15 or fewer customers, reliability data was not provided to protect customer anonymity.

- Total number of customers interrupted;
- Unique number of customers interrupted;
- SAIDI excluding MEDs: the total duration of interruption for the average customer during a year,[7] excluding MEDs; expressed in minutes.
- SAIDI including MEDs: the total duration of interruption for the average customer during a year, including MEDs; expressed in minutes.
- System Average Interruption Frequency Index (SAIFI) excluding MEDs: how often the average customer experiences a sustained interruption during a year, excluding MEDs,[8] expressed in interruptions per customer.
- SAIFI including MEDs: how often the average customer experiences a sustained interruption during a year, including MEDs; expressed in interruptions per customer.

[6] IEEE Standards Association. (2022). IEEE Guide for Electric Power Distribution Reliability Indices (IEEE Std 1366-2022). The Institute of Electrical and Electronics Engineers, Inc. p20.

[7] IEEE 1366-2022, p15.

[8] *Ibid*.

- Customer Average Interruption Duration Index (CAIDI) excluding MEDs: the average time to restore service,[9] excluding MEDs; expressed in minutes.
- CAIDI including MEDs: the average time to restore service, including MEDs; expressed in minutes.
- the Customers Experiencing Multiple Interruptions Index (CEMI-n), which indicates the percentage of individual customers experiencing n or more sustained interruptions in a year;[10] values were provided for the following metrics:
    - CEMI-4
    - CEMI-5
    - CEMI-7
    - CEMI-10
- the Customers Experiencing Long Interruption Durations Index (CELID), which indicates the percentage of individual customers that experience a single interruption of at least a given duration, in hours;[11] values were provided for the following metrics:
    - CELID-5
    - CELID-24
- The percentage of normal-weather restorations made within 8 hours: Consumers defines normal-weather conditions as those that leave less than 1% of their customers without power.[12]
- The percentage of gray-sky weather restorations made within 24 hours: Consumers defines gray-sky events as those that leave less than 10% of their customers without power.[13]
- The percentage of all-weather restorations made within 36 hours: this category considers restorations made under normal, gray-sky, and catastrophic-weather conditions.
- The percentage of catastrophic-weather restorations made within 48 hours: Consumers defines catastrophic events as those that leave at least 10% of their customers without power.[14]

[9] IEEE 1366-2022, p15.

[10] *Ibid*, p17.

[11] *Ibid*.

[12] https://www.consumersenergy.com/outages-and-safety/outage-credit

[13] *Ibid*.

[14] *Ibid*.

Demographic Data

A primary objective of this study was to compare the reliability experienced by EJ and non-EJ communities served by Consumers. As previously described, MiEJScreen calculates Overall Scores for 2010 census tracts in Michigan. Each 2010 census tract within Consumers' service territory is then classified as EJ or non-EJ on the basis of its MiEJScreen Overall Score.[15] MiEJScreen also provides other demographic data for 2010 census tracts, several of which were used in the 2010-census-tract-level reliability regression analyses discussed in subsequent sections. These other demographic data are:

- Percent Minority Percentile, which is based on "the sum of all race/ethnicity categories except White/Non-Hispanic. It includes Black, American Indian/Alaskan native, Asian, Native Hawaiian-Other Pacific Islander and two or more races." This value of this variable is not the actual percentage of the aforementioned racial/ethnic groups within a census tract's population but rather the census tract's percentile, based on the census tract's rank among the other census tracts in terms of the percentage of its population comprised by Black, Indigenous, and People of Color (BIPOC);[16]
- Poverty, which is the "percent of population living below two times the federal poverty level";[17]
- Median Household Income in the past 12 months;
- Population Density, in units of people per square mile;
- Percent Unemployed, which is the "percent of the population over the age of 16 that is unemployed and eligible for the labor force."[18] This excludes "retirees, students, homemakers, [and] institutionalized persons."; and
- Housing Burden, which is "the percent of households paying more than 30% of their income on shelter costs."[19]

Data were downloaded from the MiEJScreen: Environmental Justice Screening Tool (Version 1.0).[20]

Urbanized Area and Urban Cluster Data

To classify census tracts as urban or rural, we used the 2010 Census Urban Area shapefile for Michigan, which delineates the boundaries of each Urbanized Area (UA) and Urban Cluster (UC) in the state.[21] For the 2010 Census, a UA contained at least 50,000 people, while a UC

[15] The MiEJScreen Overall Score is called "MiEJ Score Percentile" in the data available to download through the MiEJScreen: Environmental Justice Screening Tool (Version 1.0) at the following link: https://egle.maps.arcgis.com/apps/webappviewer/index.html?id=b100011f137945138a52a35ec6d8676f

[16] MiEJScreen1.0: Michigan Environmental Justice Mapping and Screening Tool Technical Report, p10.

[17] *Ibid*, p36.

[18] *Ibid*, p41.

[19] *Ibid*, p41.

[20] https://egle.maps.arcgis.com/apps/webappviewer/index.html?id=b100011f137945138a52a35ec6d8676f

[21] The shapefile was downloaded from the Census Bureau's TIGER/Line Shapefiles web interface: https://www.census.gov/cgibin/geo/shapefiles/index.php

contained at least 2,500 and fewer than 50,000 people.[22] Areas that do not fall within a UA or UC are considered rural. Since the boundaries of UAs and UCs do not correspond to the boundaries of census tracts, we discuss in the Methods section how we determined whether each census tract should be classified as Urban or Rural.

2020 Census Tract-Level Data

Reliability Data

For 2020 through 2024, Consumers provided annual values of the same 18 reliability metrics at the 2020 Census-tract level that they provided at the 2010 Census-tract level.

Residential Involuntary Disconnection Data

Consumers provided annual counts of residential involuntary disconnections due to non-payment (also referred to in this report as "residential disconnections", or "shutoffs") for 2020 Census tracts within their service territory for each year from 2020 through 2024. For the better part of 2020, Consumers instituted a moratorium on residential disconnections in response to the COVID-19 pandemic, which this data reflects.

Demographic Data

The Census Bureau provides American Community Survey (ACS) 5-year estimates of different demographic variables. Table 1 details the ACS variables used in the analysis of disconnection rates and provides the associated codes and a brief description of the ACS census tract table data. Some variables included in the analysis of disconnection rates required additional calculations to obtain. These variables are listed in Table 2 with qualitative equations as well as references to applicable ACS codes from Table 1.

[22] https://www.census.gov/programs-surveys/geography/guidance/geoareas/urban-rural/2010-urban-rural.html

Table 1. American Community Survey variables used in the study with table codes and descriptions.

ACS Code	Estimate	Table description
B01003_001E	Total	Total Population
B11001_001E	Total Households	Household Type (Including Living Alone)
B03002_003E	Total Not Hispanic or Latino (White alone)	Hispanic or Latino Origin by Race
B19013_001E	Median	Median Household Income in Past 12 months
B17001_001E	Total	Poverty Status in Past 12 Months by Sex by Age
B17001_002E	Total for income in past 12 months below poverty level	Poverty Status in Past 12 Months by Sex by Age
B25077_001E	Median	Median Home Value (Dollars)
B23025_005E	Total in Civilian Labor Force Unemployed	Employment Status for Population 16+
B23025_003E	Total in Civilian Labor Force	Employment Status for Population 16+
B25003_001E	Total	Tenure
B25003_003E	Total Renter Occupied	Tenure
B25034_001E	Total	Year Structure Built
B25034_002E	Total Built 2020 or later	Year Structure Built
B25034_003E	Total Built 2010 to 2019	Year Structure Built
B25034_004E	Total Built 2000 to 2009	Year Structure Built
B25034_005E	Total Built 1990 to 1999	Year Structure Built

Table 2. Calculated predictor variables and associated American Community Survey reference codes. Data for Land Area were obtained from shapefiles provided by the Census Bureau.[23]

Variable	Calculation	ACS Reference
Disconnection Rate	$\frac{\#\ of\ disconnects}{Total\ \#\ of\ Households}$	$\frac{\#\ of\ disconnects}{\mathrm{B11001_001E}}$
Unemployment Rate	$\frac{Unemployed\ Population}{Civilian\ Labor\ Force} \times 100$	$\frac{\mathrm{B23025_005E}}{\mathrm{B23025_003E}} \times 100$
Percentage of Renters	$\frac{Renter - Occupied\ Housing\ Units}{Total\ Occupied\ Housing\ Units} \times 100$	$\frac{\mathrm{B25003_003E}}{\mathrm{B25003_001E}} \times 100$
Percentage of Homes built after 1990	$\frac{Built\ 1990to1999\ +\ 2000to2009\ +2010to2019\ +\ 2020\ or\ later}{Total\ Housing\ Units} \times 100$	$\frac{\mathrm{B25034_005E\ +B25034_004E\ +\ B25034_003E+B25034_002E}}{\mathrm{B25034_001E}} \times 100$
Percent Minority Population	$\left(1 - \frac{Non - Hispanic\ White\ Population}{Census\ Tract\ Population}\right) \times 100$	$\left(1 - \frac{\mathrm{B03002_003E}}{\mathrm{B01003_001E}}\right) \times 100$
Percent Below Poverty Population	$\frac{Population\ Below\ Poverty}{Population\ for whom\ Poverty\ Status\ is\ Determined} \times 100$	$\frac{\mathrm{B17001_002E}}{\mathrm{B17001_001E}} \times 100$
Population Density	$\frac{Total\ Households}{Land\ Area}$	$\frac{\mathrm{B11001_001E}}{Land\ Area}$

[23] Index of /Geo/Tiger/TIGER2020/Tract. (n.d.). https://www2.census.gov/geo/tiger/TIGER2020/TRACT/tl_2020_25_tract.zip

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Circuit-Level Data

Reliability Data

Consumers provided annual values of four reliability metrics for 2400 feeders from 2020 through 2024.

- SAIDI excluding MEDs;
- SAIDI including MEDs;
- SAIFI including MEDs; and
- SAIFI excluding MEDs.

Circuit-2010 Census Tract Overlap Data

For each feeder, Consumers provided the percentage of its length that falls within a 2010 Census tract.

Circuit Characteristics Data

Consumers provided the following data for each feeder:

- Customers per Primary Line Mile;
- Mean Canopy Cover Percentage: the percentage of the land surface covered by trees along the length of a circuit;
- Open Wire Secondary Miles;
- Primary Miles;
- Primary Underground Percentage: the percentage of a feeder's primary line mileage that is underground;
- Voltage: the voltage (kV) and configuration of phases (Delta or Wye Grounded);
- Primary Miles; and
- Year of Last Trim: the year that vegetation proximal to the feeder was most recently trimmed.

Methods

We used two types of statistical methods to assess whether there are statistically significant differences in the reliability of different groups of customers within Consumers' service territory: (1) the binary difference-in-means t-test, which assesses whether differences in the average reliability of two groups of census tracts is statistically significant; and (2) regression models, which quantify the correlation between the characteristics of a community and its reliability or between the characteristics of a circuit – including both its physical characteristics and the types of communities it serves – and its reliability. The following subsections detail how groups of census tracts were defined, how feeders were classified, and how linear regression models were specified.

Classifying 2010 Census Tracts

In addition to being classified as EJ or non-EJ, 2010 census tracts were also classified as Urban or Rural, Low Income or High Income, and Low Percent Minority Percentile or High Percent Minority Percentile as detailed in the following subsections.

Urban and Rural Census Tracts

The boundaries of UAs and UCs do not correspond exactly to the boundaries of census tracts. Because we wanted to classify each census tract in Consumers' service territory as Urban or Rural, we carried out the following steps:

1. We intersected the UA/UC shapefile with a shapefile of all census tracts in Michigan.[24]
    a. To carry out this intersection, we first re-projected both the UA/UC shapefile and the Michigan census tract shapefile into EPSG:3079, a projected Coordinate Reference System (CRS) appropriate to use for Michigan.[25]
2. We then calculated the area of each intersection of a census tract and a UA or UC.
3. For each census tract, we then determined the fraction of its area that fell within a UA or UC.
4. All census tracts with more than 50% of their area falling within any UA or UC were classified as Urban. All census tracts with 50% or less of their area within any UA or UC were classified as Rural.

Low-Income and High-Income Census Tracts

We defined Low-Income and High-Income census tracts based on the Median Household Income, Past 12 Months tabulated in MiEJScreen. 2010 census tracts with a Median Household Income, Past 12 Months value less than or equal to the 10th percentile among all census tracts within the Consumers service territory were classified as Low-Income, while all other census tracts were classified as High-Income.

[24] https://www2.census.gov/geo/pvs/tiger2010st/26_Michigan/26/tl_2010_26_tract10.zip

[25] https://epsg.org/crs_3079/NAD83-HARN-Michigan-Oblique-Mercator.html

High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile Census Tracts

We defined High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts based on the Percent Minority Percentile tabulated in MiEJScreen. 2010 census tracts with a Percent Minority Percentile ≥ 90 were classified as High Percent Minority Percentile, while all other census tracts were classified as Low Percent Minority Percentile. We selected the 90th percentile as the classification threshold based on previous work by Pradhan and Chan (2024).[26]

Classifying 2020 Census Tracts

2020 census tracts were classified as Low or High Income, and Low or High Percentage Minority Population, as detailed in the following subsections.

Low-Income and High-Income Census Tracts

We defined Low-Income and High-Income census tracts based on the Median Household Income in the past 12 months (ACS Reference B19013_001E in Table 1). 2020 census tracts with a Median Household Income in the past 12 months less than or equal to the 10th percentile among all census tracts within the Consumers service territory were classified as Low-Income, while all other census tracts were classified as High-Income.

High-Percentage-Minority-Population and Low-Percentage-Minority-Population Census Tracts

We defined High-Percentage-Minority-Percentile and Low-Percentage-Minority-Percentile census tracts based on the Percentage Minority Population value derived from ACS data as detailed in Table 2. 2020 census tracts with a Percentage Minority Population ≥ 90 were classified as High Percentage Minority Population, while all other census tracts were classified as Low Percentage Minority Population. We selected the 90th percentile as the classification threshold based on previous work by Pradhan and Chan (2024).[27]

Classifying Feeders as Serving a Group of Census Tracts

Feeders typically pass through multiple census tracts. To classify a feeder as serving a particular type of census tract of interest – such as EJ tracts or Urban tracts – we first classified census tracts into the groups of interest, using binary variables to indicate their membership in a particular group. Using the data on feeder overlap with census tracts provided by Consumers, we then determined whether any part of a feeder overlapped with a census tract in the group of interest: if so, the feeder was classified as serving the group of interest, and if not, the feeder was classified as not serving the group of interest. This approach results in a feeder with even 1% of

[26] Pradhan, B. and Chan, G. (2024). Minnesota's energy paradox: Household energy insecurity in the face of racial and economic disparities. The Electricity Journal: Vol. 37, Issue 6. p5.

[27] *Ibid*.

its length in an Urban census tract being classified as serving an urban area, just as a feeder with 99% of its length in Urban census tracts is classified as serving an urban area.

Binary Difference-in-Means t-test

A binary difference-in-means t-test assesses the statistical significance of a difference in the average of a particular quantity between two groups: in this case, the difference in reliability averaged among two groups of census tracts, such as EJ and non-EJ census tracts. It has been previously applied to compare the electric reliability experienced by groups of customers by Pradhan and Chan (2024).[28]

The first step in comparing the average reliability of two groups of census tracts is to define the groups to be compared. The average reliability of each group of census tracts (and the difference in their average reliability) is then calculated. The statistical significance of the difference in average reliabilities is assessed using Welch's two-tailed t-test, an adaptation of Student's t-test that does not assume equal population variance and is therefore more reliable when two samples have unequal variances and possibly unequal sample sizes. Since there are fewer EJ census tracts than non-EJ census tracts, we considered Welch's t-test more appropriate than Student's t-test. Other groupings of census tracts that we considered also had unequal sizes. The null hypothesis of Welch's two-tailed t-test is that is that the two populations have equal means. A p-value smaller than the chosen threshold indicates that the null hypothesis can be rejected.

Linear Regression

A linear regression model describes the relationship between a dependent variable, or the response, to one or more independent variables, or predictors. A simple linear regression has one dependent and one independent variable and can be expressed as follows:

$$y_i = \beta_0 + \beta_1 x_i + \epsilon_i$$

In the above equation, i is an index for paired observations of y_i, which denotes the dependent variable, and x_i, which denotes the independent variable. β_0 is the intercept, and β_1 is the slope, or regression coefficient. ϵ_i is the error term, and is the difference between the observed value of the dependent variable and the value predicted by the regression model.

Assumptions inherent to a linear regression model include:

1. Linearity: that the mean of the dependent variable, $\mathbb{E}(y_i)$, at each value of the independent variable, x_i, is a linear function of x_i;
2. Independence: that the residuals are independent;
3. Normality: that the residuals at each value of the independent variable, x_i, are normally distributed; and
4. Homoscedasticity: that the variance of the residuals at each value of the independent variable is constant.

[28] *Ibid.*

A multiple linear regression model relates multiple independent variables to a single dependent variable and can be expressed as follows:

$$y_i = \beta_0 + \beta_1 x_{i1} + \beta_2 x_{i2} + \cdots + \beta_p x_{ip} + \epsilon_i$$

In the preceding equation, i indexes n observations of the dependent and independent variables, that is, $i = 1, \ldots, n$, while y denotes the dependent variable, $x_1, x_2, \ldots x_p$ denote the independent variables, β_0 is the intercept, and $\beta_1, \beta_2, \ldots \beta_n$ are the regression coefficients associated with the independent variables. In addition to the previously stated assumptions inherent to a linear regression model, multiple linear regression also assumes that the independent variables are not highly correlated with each other, or multicollinear.

To fit both simple and multiple linear regression models, we use Ordinary Least Squares (OLS) to estimate the model parameters, i.e., the intercept and coefficients. For each linear regression model that was fitted, the p-values of the intercept and regression coefficients and the R^2 value of the model were evaluated. R^2 quantifies the proportion of variability in the dependent variable that is explained by the independent variables included in the model, sometimes called the goodness-of-fit of the linear regression model; R^2 takes values in the range $[0, 1]$, where a value of 0 indicates that none of the variability in the dependent variable is explained by the independent variables, while a value of 1 indicates that all of the variability in the dependent variable is explained. The p-value of a regression coefficient indicates the statistical significance of the relationship between the corresponding independent variable and the dependent variable: it tests the null hypothesis that the independent variable has no correlation with the dependent variable. If a p-value for a regression coefficient is below the significance level, we can reject the null hypothesis for the population on the basis of the sample data. If a coefficient's p-value is greater than or equal to the significance level, we do not have sufficient evidence to reject the null hypothesis.

Panel Linear Regression

We used panel linear regression to evaluate relationships between 2020 Census tract-level disconnection rates and characteristics of the communities within those census tracts. Panel regression can include both entity and time fixed effects. Entity fixed effects control for potential unobserved time-invariant characteristics of an entity (or group). Entity fixed effects for this model were evaluated at the county-level. Time fixed effects control for factors that may vary with time, but affect the entities in a dataset equally, such as year-specific shocks or trends. The general form of this linear regression model is given in the following equation:

$$y_{it} = \alpha_c + X_{it}\beta + \lambda_t + \epsilon_{it}$$

In the above equation,

- y_{it} is the disconnection rate in tract i at year t;
- X_{it} denotes the set of independent variables in tract *i* in year *t*;
- α_c denotes the county-level fixed effects;
- λ_t denotes time fixed effects; and
- ϵ_{it} is an error term.

While the generalized formulation of panel linear regression includes both entity and time fixed effects, a panel regression can be fit using neither, only time fixed effects, only county-level fixed effects, or both. In the current study, we use both entity and time fixed effects to account for unobserved heterogeneity in disconnection rates across counties as well as for region-wide year-to-year effects.

Mixed-Effects Linear Regression

We used a mixed-effects linear regression model to analyze how feeder reliability varies as a function of both feeder characteristics and population characteristics of the census tracts served by a feeder. A mixed-effects linear regression model includes both fixed effects and random effects. Fixed effects are those which are the same for all feeders, while random effects can change from feeder to feeder. The following equation gives a general formulation for mixed-effects linear regression models.

$$Y_{it} = \beta X_i + \gamma_t + u_i + \epsilon_{it}$$

In the above equation,

- Y_{it} denotes the dependent variable for feeder i in year t;
- β denotes the vector of fixed-effects coefficients;
- γ_t denotes year fixed effects;
- X_i is the vector of predictor variables for feeder i;
- u_i is the random effect for feeder i; and
- ϵ_{it} is the residual error term for individual observations.

We chose to model feeder reliability using a mixed-effects linear regression model due to repeated measures (annual measurements of the reliability of each feeder) and potential correlation of within-feeder observations. Mixed models account for both within-feeder and between-feeder variability that a traditional linear regression may not capture. The feeder effect was included as a random intercept to account for repeated measures, capturing unobserved differences between feeders. Fixed effects account for variability due to observed feeder and population characteristics.

For similar reasons, we also modeled the reliability experienced by customers in different census tracts using a mixed-effects linear regression model. For the census-tract-level regression models, Y_{it} in the above equation denotes the reliability metric for census tract i in year t, and u_i is the random effect for census tract i. The census-tract-level regression models also include an additional term for county-level fixed effects, denoted α_c.

Because mixed-effects linear regression models consider multiple distinct sources of variability, R^2 is not considered a reliable measure of fit or predictive power. To assess the relative fit of different mixed-effects linear regression models, we therefore used two common information criteria: the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC). Lower values of the AIC and the BIC for a particular model indicate a better fit relative to other models. The following equation gives the AIC.

$$AIC = 2k - 2\ln(\hat{L})$$

In the above equation, k denotes the number of model parameters and $\hat{L}$ denotes the likelihood of the model, or the probability of observing the data under the assumed model parameters. A higher likelihood means the model better explains the observed data. The following equation gives the BIC.

$$AIC = 2k - 2\ln(\hat{L})\, BIC = k\ln(n) - 2\ln(\hat{L})$$

In the preceding equation, n denotes the number of observations. Both the AIC and the BIC penalize models that have more parameters to discourage overfitting, but the BIC has a stricter penalty than the AIC. We calculate and compare the AIC and BIC of each mixed-effects linear regression model considered.

We also calculate the Intraclass Coefficient (ICC) for each mixed-effects linear regression model considered. As shown in the following equation, the ICC is the ratio of the amount of variability in the model explained by between-group variation to the total amount of variability in the model, which is the sum of the between-group and within-group variation.

$$ICC = \frac{\sigma^2_{between}}{\sigma^2_{between} + \sigma^2_{within}}$$

In this study, the "group" refers to an individual feeder. In the above equation, $\sigma^2_{between}$ therefore denotes the between-feeder variance, which captures how much each feeder's baseline reliability differs from the average feeder reliability, and σ^2_{within} denotes the within-feeder variance, which captures the variability of a given feeder's reliability over time.

The ICC of a mixed-effects linear regression model can range from 0 and 1: values closer to 0 indicate greater within-feeder variability, and values closer to one indicate greater between-feeder variability. The results of the ICC analysis for each model are compared to assess how including various effects describe this variability. The aim of calculating the ICC for different mixed-effects linear regression models was to determine for each model how much of the variability in the reliability metrics could be attributed to between-feeder differences and which characteristics best describe the observed differences.

Regression Analysis Results: Reliability

Descriptive Analysis: Average Reliability of 2010 Census Tracts

The average value of each reliability metric in each year from 2020 through 2024 is shown in Table 3, considering all 1050 census tracts in Consumers' service territory for which reliability data was available. These values are provided as a reference for the regression coefficients reported and discussed in subsequent sections. Similarly, the average value of each feeder-level reliability metric in each year from 2020 through 2024 is shown in Table 4.

Table 3. The average value (over all 1050 of the 2010 census tracts in Consumers' service territory for which reliability data was provided) of each census-tract-level reliability metric in each year from 2020 through 2024.

Reliability Metric	2020	2021	2022	2023	2024
Unique Customers with an Interruption	1113.87	1211.56	1102.35	1142.70	1088.09
Total Customer Interruptions	2363.38	2827.99	2281.05	2452.29	2382.12
SAIDI including MEDs	511.22	930.59	447.32	911.41	478.95
SAIDI excluding MEDs	195.52	239.23	181.27	179.70	160.90
SAIFI including MEDs	1.32	1.61	1.26	1.38	1.31
SAIFI excluding MEDs	1.01	1.07	0.96	0.97	0.89
CAIDI including MEDs	363.92	518.43	345.51	529.50	346.91
CAIDI excluding MEDs	191.92	211.60	188.66	188.96	182.07
CEMI-4	0.09	0.13	0.09	0.11	0.11
CEMI-5	0.05	0.07	0.05	0.05	0.06
CEMI-7	0.01	0.02	0.01	0.02	0.02
CEMI-10	0.00	0.00	0.00	0.00	0.00
CELID-5	0.27	0.39	0.27	0.35	0.29
CELID-24	0.08	0.16	0.06	0.16	0.07
Percent of all-weather restorations made within 36 hours	0.97	0.94	0.98	0.93	0.98
Percent of catastrophic-weather restorations made within 48 hours	0.89	0.80	0.94	0.86	0.95
Percent of normal-weather restorations made within 8 hours	0.95	0.93	0.94	0.94	0.94
Percent of gray-sky-weather restorations made within 24 hours	0.93	0.90	0.89	0.97	0.94

Table 4. The average value (over all feeders in Consumers distribution system) of each of four feeder-level reliability metrics in each year from 2020 through 2024.

Reliability Metric	2020	2021	2022	2023	2024
SAIDI excluding MEDs	190.65	229.77	179.80	190.76	178.09
SAIDI including MEDs	527.19	941.49	459.66	1063.82	578.03
SAIFI excluding MEDs	1.01	1.06	0.92	1.00	0.98
SAIFI including MEDs	1.33	1.59	1.22	1.46	1.47

Comparing the Average Reliability of Groups of Census Tracts

To assess whether there were statistically significant differences in the reliability of groups of census tracts in the Consumers service territory from 2020 through 2024, we carried out the binary difference-in-means *t*-test previously described for each of the following paired groups of census tracts in each year for each reliability metric tabulated at the 2010 Census-tract level:

- EJ and non-EJ;
- Urban and Rural;
- Low Income and High Income; and
- High Percent Minority Percentile and Low Percent Minority Percentile.

The following subsections detail the findings of each set of comparisons.

EJ and Non-EJ Census Tracts

For EJ and Non-EJ census tracts, the results of the binary difference-in-means t-test for each reliability metric and each year from 2020 through 2024 are shown in Table 5. Statistically significant differences in the mean reliability experienced by EJ and non-EJ census tracts are observed for many reliability metrics and years, including Unique Customers with an Interruption and Total Customer Interruptions; SAIDI, SAIFI, and CAIDI, each including and excluding MEDs; CEMI-4, -5, -7, and -10; CELID-5 and -24; and the percentage of all-weather restorations made within 36 hours. In contrast, the differences in mean reliability experienced by EJ and Non-EJ census tracts in terms of the percentage of normal-weather restorations made within 8 hours and the percentage of catastrophic-weather restorations made within 48 hours are not statistically significant for any of the years included in this analysis. As Table 5 shows, when statistically significant differences in the mean reliability of these two groups are observed, it is consistently the EJ census tracts that experience better average reliability.

Table 5. Comparison of census-tract-level reliability metrics for each year from 2020 through 2024 averaged for EJ census tracts and for non-EJ census tracts. The difference is calculated by subtracting the EJ Mean from the Non-EJ Mean. Statistical significance is assessed at $\alpha = 0.05$, and the group that experiences better reliability is assessed only for statistically significant differences in mean reliability.

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.13E+03	8.90E+02	2.37E+02	6.62E-03	TRUE	EJ
	2021	1.23E+03	8.19E+02	4.14E+02	5.55E-07	TRUE	EJ
	2022	1.12E+03	8.52E+02	2.64E+02	2.86E-03	TRUE	EJ
	2023	1.16E+03	8.10E+02	3.52E+02	6.20E-05	TRUE	EJ
	2024	1.10E+03	7.97E+02	3.08E+02	2.97E-04	TRUE	EJ
Total Customer Interruptions	2020	2.39E+03	1.82E+03	5.72E+02	1.33E-02	TRUE	EJ
	2021	2.91E+03	1.39E+03	1.52E+03	5.83E-16	TRUE	EJ
	2022	2.31E+03	1.77E+03	5.42E+02	5.06E-02	FALSE	N/A
	2023	2.50E+03	1.56E+03	9.40E+02	3.44E-04	TRUE	EJ
	2024	2.44E+03	1.43E+03	1.01E+03	1.56E-06	TRUE	EJ
SAIDI including MEDs	2020	5.24E+02	2.85E+02	2.39E+02	5.69E-05	TRUE	EJ
	2021	9.66E+02	3.06E+02	6.60E+02	3.74E-28	TRUE	EJ
	2022	4.56E+02	2.90E+02	1.66E+02	1.49E-04	TRUE	EJ
	2023	9.36E+02	4.76E+02	4.60E+02	2.50E-05	TRUE	EJ
	2024	4.90E+02	2.89E+02	2.00E+02	1.40E-05	TRUE	EJ
SAIDI excluding MEDs	2020	1.99E+02	1.38E+02	6.08E+01	5.05E-05	TRUE	EJ
	2021	2.45E+02	1.34E+02	1.11E+02	3.55E-07	TRUE	EJ
	2022	1.84E+02	1.28E+02	5.60E+01	2.02E-04	TRUE	EJ
	2023	1.84E+02	1.10E+02	7.36E+01	6.37E-10	TRUE	EJ
	2024	1.64E+02	1.06E+02	5.85E+01	5.07E-05	TRUE	EJ
SAIFI including MEDs	2020	1.33E+00	1.16E+00	1.75E-01	1.01E-01	FALSE	N/A
	2021	1.65E+00	1.05E+00	5.98E-01	2.69E-08	TRUE	EJ
	2022	1.27E+00	1.20E+00	7.19E-02	6.35E-01	FALSE	N/A
	2023	1.40E+00	1.04E+00	3.57E-01	5.60E-03	TRUE	EJ
	2024	1.33E+00	9.16E-01	4.14E-01	1.27E-04	TRUE	EJ
SAIFI excluding MEDs	2020	1.01E+00	9.36E-01	7.63E-02	4.32E-01	FALSE	N/A
	2021	1.09E+00	7.92E-01	2.93E-01	1.41E-03	TRUE	EJ
	2022	9.61E-01	8.85E-01	7.55E-02	4.25E-01	FALSE	N/A
	2023	9.76E-01	7.85E-01	1.91E-01	2.75E-02	TRUE	EJ
	2024	9.03E-01	6.90E-01	2.13E-01	1.78E-02	TRUE	EJ
CAIDI including MEDs	2020	3.71E+02	2.30E+02	1.41E+02	9.12E-07	TRUE	EJ
	2021	5.30E+02	3.16E+02	2.14E+02	8.10E-08	TRUE	EJ
	2022	3.49E+02	2.76E+02	7.30E+01	2.81E-03	TRUE	EJ
	2023	5.36E+02	4.09E+02	1.28E+02	5.02E-02	FALSE	N/A
	2024	3.49E+02	3.17E+02	3.15E+01	2.61E-01	FALSE	N/A
CAIDI excluding MEDs	2020	1.94E+02	1.63E+02	3.03E+01	3.64E-03	TRUE	EJ
	2021	2.14E+02	1.77E+02	3.66E+01	2.09E-02	TRUE	EJ

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
	2022	1.90E+02	1.64E+02	2.58E+01	1.85E-02	TRUE	EJ
	2023	1.90E+02	1.75E+02	1.43E+01	3.57E-01	FALSE	N/A
	2024	1.83E+02	1.64E+02	1.91E+01	1.22E-01	FALSE	N/A
CEMI-4	2020	9.27E-02	6.30E-02	2.97E-02	1.14E-01	FALSE	N/A
	2021	1.35E-01	3.33E-02	1.02E-01	7.35E-17	TRUE	EJ
	2022	9.26E-02	8.33E-02	9.27E-03	7.09E-01	FALSE	N/A
	2023	1.09E-01	6.48E-02	4.46E-02	4.68E-02	TRUE	EJ
	2024	1.11E-01	4.29E-02	6.79E-02	2.01E-05	TRUE	EJ
CEMI-5	2020	4.68E-02	3.19E-02	1.50E-02	2.71E-01	FALSE	N/A
	2021	7.55E-02	1.09E-02	6.47E-02	8.31E-23	TRUE	EJ
	2022	4.59E-02	4.29E-02	3.05E-03	8.66E-01	FALSE	N/A
	2023	5.56E-02	3.07E-02	2.49E-02	6.01E-02	FALSE	N/A
	2024	6.28E-02	1.73E-02	4.54E-02	7.17E-08	TRUE	EJ
CEMI-7	2020	1.25E-02	3.78E-03	8.75E-03	6.95E-04	TRUE	EJ
	2021	2.09E-02	1.28E-04	2.07E-02	5.36E-21	TRUE	EJ
	2022	9.95E-03	9.26E-03	6.86E-04	9.14E-01	FALSE	N/A
	2023	1.60E-02	3.88E-03	1.22E-02	2.29E-05	TRUE	EJ
	2024	1.97E-02	1.69E-03	1.80E-02	2.54E-15	TRUE	EJ
CEMI-10	2020	2.92E-03	1.00E-04	2.82E-03	1.14E-02	TRUE	EJ
	2021	2.22E-03	0.00E+00	2.22E-03	5.07E-07	TRUE	EJ
	2022	1.43E-03	5.04E-05	1.38E-03	6.36E-03	TRUE	EJ
	2023	2.32E-03	9.52E-06	2.31E-03	9.66E-06	TRUE	EJ
	2024	4.79E-03	1.30E-05	4.77E-03	3.99E-05	TRUE	EJ
CELID-5	2020	2.77E-01	1.71E-01	1.06E-01	1.66E-03	TRUE	EJ
	2021	4.03E-01	2.08E-01	1.95E-01	1.20E-07	TRUE	EJ
	2022	2.77E-01	2.16E-01	6.09E-02	4.16E-02	TRUE	EJ
	2023	3.58E-01	2.24E-01	1.35E-01	7.58E-04	TRUE	EJ
	2024	3.00E-01	1.95E-01	1.05E-01	2.94E-04	TRUE	EJ
CELID-24	2020	8.20E-02	3.83E-02	4.37E-02	1.47E-02	TRUE	EJ
	2021	1.66E-01	3.00E-02	1.36E-01	1.17E-25	TRUE	EJ
	2022	6.15E-02	3.39E-02	2.76E-02	1.70E-02	TRUE	EJ
	2023	1.68E-01	8.74E-02	8.06E-02	9.36E-04	TRUE	EJ
	2024	7.17E-02	5.51E-02	1.66E-02	2.69E-01	FALSE	N/A
Percent of all-weather restorations made within 36 hours	2020	9.69E-01	9.91E-01	-2.21E-02	1.44E-04	TRUE	EJ
	2021	9.44E-01	9.70E-01	-2.62E-02	3.21E-02	TRUE	EJ
	2022	9.78E-01	9.96E-01	-1.81E-02	1.98E-11	TRUE	EJ
	2023	9.30E-01	9.55E-01	-2.44E-02	8.37E-02	FALSE	N/A
	2024	9.77E-01	9.89E-01	-1.21E-02	3.95E-02	TRUE	EJ
Percent of catastrophic-weather restorations made within 48 hours	2020	8.92E-01	8.87E-01	5.32E-03	9.01E-01	FALSE	N/A
	2021	7.95E-01	8.25E-01	-2.94E-02	5.22E-01	FALSE	N/A
	2022	9.40E-01	9.52E-01	-1.20E-02	7.43E-01	FALSE	N/A

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
	2023	8.56E-01	8.51E-01	5.57E-03	9.04E-01	FALSE	N/A
	2024	9.54E-01	9.49E-01	4.41E-03	8.28E-01	FALSE	N/A
Percent of normal-weather restorations made within 8 hours	2020	9.52E-01	9.48E-01	4.25E-03	8.30E-01	FALSE	N/A
	2021	9.34E-01	9.43E-01	-9.71E-03	5.37E-01	FALSE	N/A
	2022	9.46E-01	9.25E-01	2.04E-02	2.76E-01	FALSE	N/A
	2023	9.40E-01	9.25E-01	1.51E-02	5.27E-01	FALSE	N/A
	2024	9.42E-01	9.60E-01	-1.71E-02	1.89E-01	FALSE	N/A
Percent of gray-sky weather restorations made within 24 hours	2020	9.30E-01	9.91E-01	-6.15E-02	1.03E-16	TRUE	EJ
	2021	8.93E-01	9.56E-01	-6.39E-02	4.88E-05	TRUE	EJ
	2022	8.94E-01	8.96E-01	-2.50E-03	9.33E-01	FALSE	N/A
	2023	9.73E-01	9.43E-01	2.98E-02	2.80E-01	FALSE	N/A
	2024	9.45E-01	9.32E-01	1.25E-02	6.96E-01	FALSE	N/A

Urban and Rural Census Tracts

For Urban and Rural census tracts, the results of the binary difference-in-means t-test for each reliability metric and each year from 2020 through 2024 are shown in Table 6. Statistically significant differences in the mean reliability experienced by Rural and Urban census tracts are observed for most reliability metrics and years, including Unique Customers with an Interruption and Total Customer Interruptions; SAIDI, SAIFI, and CAIDI, each including and excluding MEDs; CEMI-4, -5, -7, and -10; CELID-5 and -24. In contrast, the differences in mean reliability experienced by Urban and Rural census tracts in terms of the percentage of normal-weather restorations made within 8 hours and the percentage of catastrophic-weather restorations made within 48 hours are not statistically significant for any of the years included in this analysis. As Table 6 shows, when statistically significant differences in the mean reliability of these two groups are observed, it is consistently the Urban census tracts that experience better average reliability.

Table 6. Comparison of census-tract-level reliability metrics for each year from 2020 through 2024 averaged for rural census tracts and for urban census tracts. Significance is assessed at $\alpha = 0.05$.

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.24E+03	9.41E+02	3.03E+02	1.30E-11	TRUE	Urban
	2021	1.37E+03	1.01E+03	3.58E+02	7.08E-14	TRUE	Urban
	2022	1.22E+03	9.51E+02	2.65E+02	1.57E-08	TRUE	Urban
	2023	1.24E+03	1.01E+03	2.32E+02	1.89E-06	TRUE	Urban
	2024	1.22E+03	9.15E+02	3.04E+02	1.53E-10	TRUE	Urban
Total Customer Interruptions	2020	2.91E+03	1.64E+03	1.28E+03	2.32E-25	TRUE	Urban
	2021	3.66E+03	1.72E+03	1.94E+03	1.57E-43	TRUE	Urban
	2022	2.76E+03	1.65E+03	1.11E+03	9.54E-20	TRUE	Urban
	2023	2.93E+03	1.82E+03	1.11E+03	2.21E-17	TRUE	Urban

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
	2024	2.99E+03	1.57E+03	1.42E+03	9.00E-25	TRUE	Urban
SAIDI including MEDs	2020	6.65E+02	3.07E+02	3.58E+02	6.84E-23	TRUE	Urban
	2021	1.35E+03	3.80E+02	9.65E+02	4.73E-55	TRUE	Urban
	2022	5.86E+02	2.63E+02	3.23E+02	3.78E-36	TRUE	Urban
	2023	1.13E+03	6.24E+02	5.05E+02	1.08E-09	TRUE	Urban
	2024	6.20E+02	2.91E+02	3.29E+02	2.51E-21	TRUE	Urban
SAIDI excluding MEDs	2020	2.49E+02	1.25E+02	1.24E+02	1.63E-26	TRUE	Urban
	2021	3.15E+02	1.38E+02	1.77E+02	2.66E-31	TRUE	Urban
	2022	2.30E+02	1.16E+02	1.14E+02	2.19E-31	TRUE	Urban
	2023	2.18E+02	1.30E+02	8.81E+01	9.70E-20	TRUE	Urban
	2024	2.08E+02	9.83E+01	1.10E+02	1.04E-30	TRUE	Urban
SAIFI including MEDs	2020	1.62E+00	9.26E-01	6.96E-01	2.67E-34	TRUE	Urban
	2021	2.09E+00	9.90E-01	1.10E+00	1.21E-67	TRUE	Urban
	2022	1.53E+00	9.17E-01	6.09E-01	4.10E-30	TRUE	Urban
	2023	1.62E+00	1.05E+00	5.69E-01	2.66E-21	TRUE	Urban
	2024	1.63E+00	8.77E-01	7.55E-01	1.01E-34	TRUE	Urban
SAIFI excluding MEDs	2020	1.20E+00	7.50E-01	4.53E-01	9.05E-23	TRUE	Urban
	2021	1.32E+00	7.43E-01	5.73E-01	9.28E-36	TRUE	Urban
	2022	1.15E+00	7.05E-01	4.42E-01	8.53E-26	TRUE	Urban
	2023	1.13E+00	7.53E-01	3.75E-01	3.10E-18	TRUE	Urban
	2024	1.11E+00	6.07E-01	4.99E-01	1.18E-29	TRUE	Urban
CAIDI including MEDs	2020	3.88E+02	3.32E+02	5.54E+01	6.51E-03	TRUE	Urban
	2021	6.14E+02	3.92E+02	2.22E+02	6.14E-21	TRUE	Urban
	2022	3.83E+02	2.96E+02	8.61E+01	3.26E-08	TRUE	Urban
	2023	5.44E+02	5.11E+02	3.30E+01	3.29E-01	FALSE	N/A
	2024	3.52E+02	3.40E+02	1.26E+01	4.29E-01	FALSE	N/A
CAIDI excluding MEDs	2020	2.01E+02	1.80E+02	2.03E+01	6.86E-03	TRUE	Urban
	2021	2.29E+02	1.88E+02	4.10E+01	1.11E-06	TRUE	Urban
	2022	2.00E+02	1.74E+02	2.61E+01	8.15E-07	TRUE	Urban
	2023	1.97E+02	1.78E+02	1.90E+01	1.37E-03	TRUE	Urban
	2024	1.91E+02	1.71E+02	2.02E+01	1.83E-04	TRUE	Urban
CEMI-4	2020	1.32E-01	3.65E-02	9.58E-02	5.75E-30	TRUE	Urban
	2021	2.01E-01	3.58E-02	1.65E-01	1.60E-61	TRUE	Urban
	2022	1.29E-01	4.32E-02	8.58E-02	4.83E-25	TRUE	Urban
	2023	1.47E-01	5.42E-02	9.27E-02	2.08E-21	TRUE	Urban
	2024	1.55E-01	4.33E-02	1.12E-01	3.90E-33	TRUE	Urban
CEMI-5	2020	7.10E-02	1.29E-02	5.81E-02	4.71E-25	TRUE	Urban
	2021	1.16E-01	1.38E-02	1.02E-01	4.47E-42	TRUE	Urban
	2022	6.58E-02	1.93E-02	4.65E-02	1.14E-17	TRUE	Urban
	2023	7.96E-02	2.10E-02	5.87E-02	7.33E-21	TRUE	Urban
	2024	9.18E-02	1.86E-02	7.31E-02	2.88E-27	TRUE	Urban

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
CEMI-7	2020	2.01E-02	1.39E-03	1.87E-02	2.46E-11	TRUE	Urban
	2021	3.20E-02	3.54E-03	2.84E-02	1.04E-13	TRUE	Urban
	2022	1.51E-02	3.03E-03	1.21E-02	5.86E-08	TRUE	Urban
	2023	2.52E-02	2.49E-03	2.27E-02	3.04E-13	TRUE	Urban
	2024	2.96E-02	4.40E-03	2.52E-02	4.74E-12	TRUE	Urban
CEMI-10	2020	4.83E-03	5.11E-05	4.78E-03	9.64E-03	TRUE	Urban
	2021	3.68E-03	3.39E-06	3.67E-03	4.79E-07	TRUE	Urban
	2022	2.37E-03	1.39E-05	2.36E-03	4.79E-03	TRUE	Urban
	2023	3.84E-03	2.25E-05	3.81E-03	1.03E-05	TRUE	Urban
	2024	6.01E-03	2.57E-03	3.44E-03	1.39E-01	FALSE	N/A
CELID-5	2020	3.42E-01	1.77E-01	1.65E-01	4.14E-26	TRUE	Urban
	2021	5.11E-01	2.35E-01	2.76E-01	4.80E-58	TRUE	Urban
	2022	3.33E-01	1.94E-01	1.39E-01	8.27E-21	TRUE	Urban
	2023	3.98E-01	2.89E-01	1.09E-01	2.36E-08	TRUE	Urban
	2024	3.58E-01	2.11E-01	1.47E-01	6.75E-19	TRUE	Urban
CELID-24	2020	1.06E-01	4.51E-02	6.07E-02	7.02E-11	TRUE	Urban
	2021	2.39E-01	5.33E-02	1.85E-01	5.01E-52	TRUE	Urban
	2022	8.23E-02	3.06E-02	5.18E-02	2.57E-15	TRUE	Urban
	2023	1.92E-01	1.27E-01	6.53E-02	4.35E-05	TRUE	Urban
	2024	9.03E-02	4.50E-02	4.53E-02	2.25E-07	TRUE	Urban
Percent of all-weather restorations made within 36 hours	2020	9.70E-01	9.69E-01	1.73E-03	7.47E-01	FALSE	N/A
	2021	9.28E-01	9.68E-01	-4.04E-02	5.62E-13	TRUE	Urban
	2022	9.71E-01	9.89E-01	-1.75E-02	2.09E-06	TRUE	Urban
	2023	9.32E-01	9.32E-01	-2.32E-05	9.98E-01	FALSE	N/A
	2024	9.77E-01	9.79E-01	-1.53E-03	7.26E-01	FALSE	N/A
Percent of catastrophic-weather restorations made within 48 hours	2020	9.03E-01	8.75E-01	2.88E-02	7.13E-02	FALSE	N/A
	2021	7.87E-01	8.12E-01	-2.54E-02	1.98E-01	FALSE	N/A
	2022	9.37E-01	9.46E-01	-8.67E-03	5.46E-01	FALSE	N/A
	2023	8.59E-01	8.51E-01	8.30E-03	6.34E-01	FALSE	N/A
	2024	9.57E-01	9.48E-01	8.55E-03	3.96E-01	FALSE	N/A
Percent of normal-weather restorations made within 8 hours	2020	9.50E-01	9.55E-01	-4.98E-03	4.48E-01	FALSE	N/A
	2021	9.30E-01	9.40E-01	-1.05E-02	1.41E-01	FALSE	N/A
	2022	9.49E-01	9.39E-01	9.36E-03	2.16E-01	FALSE	N/A
	2023	9.43E-01	9.35E-01	7.59E-03	3.33E-01	FALSE	N/A
	2024	9.43E-01	9.44E-01	-1.36E-03	8.61E-01	FALSE	N/A
Percent of gray-sky weather restorations made within 24 hours	2020	9.23E-01	9.47E-01	-2.39E-02	2.24E-02	TRUE	Urban
	2021	8.99E-01	8.91E-01	8.55E-03	4.95E-01	FALSE	N/A
	2022	8.78E-01	9.15E-01	-3.70E-02	2.79E-03	TRUE	Urban
	2023	9.75E-01	9.65E-01	9.79E-03	2.69E-01	FALSE	N/A
	2024	9.40E-01	9.50E-01	-9.69E-03	3.49E-01	FALSE	N/A

Low-Income and High-Income Census Tracts

For Low-Income and High-Income census tracts, the results of the binary difference-in-means t-test for each reliability metric and each year from 2020 through 2024 are shown in Table 7. Statistically significant differences in the mean reliability experienced by Low-Income and High-Income census tracts are observed for many reliability metrics and years, including Unique Customers with an Interruption and Total Customer Interruptions; SAIDI and SAIFI, each including and excluding MEDs; CEMI-4, -5, -7, and -10; and CELID-5 and -24. In contrast, the differences in mean reliability experienced by Low-Income and High-Income census tracts in terms of CAIDI excluding MEDs, the percentage of normal-weather restorations made within 8 hours, and the percentage of gray-sky-weather restorations made within 24 hours are not statistically significant for any of the years included in this analysis. As Table 7 shows, when statistically significant differences in the mean reliability of these two groups are observed, it is almost always the Low-Income census tracts that experience better average reliability. There are three exceptions to that pattern: the average percentage of all-weather restorations within 36 hours in 2020 among High-Income census tracts was greater than among Low-Income census tracts; and the average percentage of catastrophic-weather restorations within 48 hours in 2020 and 2024 among High-Income census tracts was greater than among Low-Income census tracts.

Table 7. Comparison of census-tract-level reliability metrics for each year from 2020 through 2024 averaged for high-income census tracts and for low-income census tracts. Significance is assessed at $\alpha = 0.05$.

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.16E+03	6.83E+02	4.79E+02	5.98E-13	TRUE	Low
	2021	1.26E+03	7.75E+02	4.85E+02	8.84E-13	TRUE	Low
	2022	1.15E+03	6.50E+02	5.03E+02	6.21E-12	TRUE	Low
	2023	1.19E+03	7.04E+02	4.88E+02	2.89E-12	TRUE	Low
	2024	1.14E+03	5.93E+02	5.50E+02	1.19E-15	TRUE	Low
Total Customer Interruptions	2020	2.48E+03	1.31E+03	1.17E+03	1.29E-10	TRUE	Low
	2021	2.97E+03	1.59E+03	1.37E+03	4.72E-09	TRUE	Low
	2022	2.41E+03	1.11E+03	1.30E+03	5.53E-15	TRUE	Low
	2023	2.59E+03	1.25E+03	1.34E+03	1.61E-16	TRUE	Low
	2024	2.51E+03	1.25E+03	1.26E+03	5.68E-06	TRUE	Low
SAIDI including MEDs	2020	5.27E+02	3.71E+02	1.56E+02	1.96E-03	TRUE	Low
	2021	9.85E+02	4.49E+02	5.36E+02	1.60E-15	TRUE	Low
	2022	4.68E+02	2.58E+02	2.10E+02	3.05E-10	TRUE	Low
	2023	9.58E+02	5.00E+02	4.58E+02	7.43E-06	TRUE	Low
	2024	4.98E+02	3.06E+02	1.92E+02	5.31E-03	TRUE	Low
SAIDI excluding MEDs	2020	2.03E+02	1.32E+02	7.11E+01	1.28E-06	TRUE	Low
	2021	2.45E+02	1.85E+02	5.99E+01	1.19E-03	TRUE	Low
	2022	1.86E+02	1.42E+02	4.34E+01	7.56E-03	TRUE	Low
	2023	1.85E+02	1.33E+02	5.17E+01	6.58E-04	TRUE	Low
	2024	1.66E+02	1.18E+02	4.82E+01	4.16E-03	TRUE	Low

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
SAIFI including MEDs	2020	1.37E+00	9.33E-01	4.33E-01	1.47E-07	TRUE	Low
	2021	1.66E+00	1.21E+00	4.47E-01	2.19E-05	TRUE	Low
	2022	1.31E+00	8.39E-01	4.72E-01	1.62E-09	TRUE	Low
	2023	1.42E+00	9.78E-01	4.45E-01	2.18E-07	TRUE	Low
	2024	1.36E+00	8.26E-01	5.35E-01	1.04E-06	TRUE	Low
SAIFI excluding MEDs	2020	1.04E+00	7.09E-01	3.33E-01	3.16E-06	TRUE	Low
	2021	1.08E+00	9.39E-01	1.46E-01	7.68E-02	FALSE	N/A
	2022	9.83E-01	7.19E-01	2.64E-01	6.92E-05	TRUE	Low
	2023	9.89E-01	7.64E-01	2.25E-01	1.05E-03	TRUE	Low
	2024	9.25E-01	5.98E-01	3.27E-01	8.26E-07	TRUE	Low
CAIDI including MEDs	2020	3.56E+02	4.33E+02	-7.68E+01	9.30E-02	FALSE	N/A
	2021	5.29E+02	4.21E+02	1.08E+02	7.77E-03	TRUE	Low
	2022	3.49E+02	3.13E+02	3.59E+01	2.81E-01	FALSE	N/A
	2023	5.42E+02	4.15E+02	1.28E+02	1.31E-02	TRUE	Low
	2024	3.45E+02	3.67E+02	-2.25E+01	5.06E-01	FALSE	N/A
CAIDI excluding MEDs	2020	1.91E+02	2.04E+02	-1.36E+01	3.29E-01	FALSE	N/A
	2021	2.11E+02	2.17E+02	-6.03E+00	6.85E-01	FALSE	N/A
	2022	1.88E+02	1.99E+02	-1.11E+01	2.62E-01	FALSE	N/A
	2023	1.90E+02	1.81E+02	9.17E+00	3.32E-01	FALSE	N/A
	2024	1.81E+02	1.94E+02	-1.36E+01	1.89E-01	FALSE	N/A
CEMI-4	2020	9.65E-02	4.37E-02	5.28E-02	7.02E-06	TRUE	Low
	2021	1.37E-01	6.25E-02	7.49E-02	2.31E-06	TRUE	Low
	2022	9.86E-02	3.34E-02	6.52E-02	3.94E-13	TRUE	Low
	2023	1.14E-01	4.70E-02	6.67E-02	2.86E-08	TRUE	Low
	2024	1.15E-01	4.13E-02	7.32E-02	4.00E-08	TRUE	Low
CEMI-5	2020	4.89E-02	2.05E-02	2.84E-02	1.77E-04	TRUE	Low
	2021	7.66E-02	3.15E-02	4.52E-02	6.90E-05	TRUE	Low
	2022	4.95E-02	1.20E-02	3.75E-02	2.93E-13	TRUE	Low
	2023	5.85E-02	1.70E-02	4.15E-02	7.42E-12	TRUE	Low
	2024	6.48E-02	2.07E-02	4.40E-02	3.64E-05	TRUE	Low
CEMI-7	2020	1.31E-02	2.87E-03	1.02E-02	1.77E-06	TRUE	Low
	2021	2.14E-02	5.11E-03	1.63E-02	1.93E-05	TRUE	Low
	2022	1.09E-02	9.28E-04	9.98E-03	2.08E-11	TRUE	Low
	2023	1.69E-02	2.21E-03	1.47E-02	2.32E-11	TRUE	Low
	2024	1.98E-02	9.38E-03	1.04E-02	1.67E-01	FALSE	N/A
CEMI-10	2020	3.06E-03	2.34E-04	2.83E-03	1.71E-02	TRUE	Low
	2021	2.31E-03	1.76E-04	2.14E-03	1.36E-05	TRUE	Low
	2022	1.51E-03	2.64E-05	1.48E-03	5.29E-03	TRUE	Low
	2023	2.44E-03	5.03E-06	2.43E-03	9.20E-06	TRUE	Low
	2024	4.59E-03	4.03E-03	5.56E-04	8.93E-01	FALSE	N/A
CELID-5	2020	2.80E-01	1.94E-01	8.67E-02	2.21E-04	TRUE	Low

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
	2021	4.05E-01	2.81E-01	1.24E-01	1.40E-05	TRUE	Low
	2022	2.83E-01	1.90E-01	9.31E-02	1.70E-04	TRUE	Low
	2023	3.65E-01	2.28E-01	1.37E-01	1.17E-06	TRUE	Low
	2024	3.08E-01	1.75E-01	1.32E-01	5.85E-08	TRUE	Low
CELID-24	2020	8.12E-02	6.62E-02	1.50E-02	3.12E-01	FALSE	N/A
	2021	1.70E-01	6.32E-02	1.07E-01	5.03E-14	TRUE	Low
	2022	6.24E-02	3.89E-02	2.35E-02	2.43E-02	TRUE	Low
	2023	1.73E-01	8.49E-02	8.77E-02	2.79E-05	TRUE	Low
	2024	7.38E-02	4.42E-02	2.96E-02	1.37E-02	TRUE	Low
Percent of all-weather restorations made within 36 hours	2020	9.73E-01	9.44E-01	2.88E-02	3.33E-02	TRUE	High
	2021	9.44E-01	9.57E-01	-1.34E-02	1.77E-01	FALSE	N/A
	2022	9.79E-01	9.81E-01	-2.49E-03	7.86E-01	FALSE	N/A
	2023	9.29E-01	9.51E-01	-2.16E-02	6.95E-02	FALSE	N/A
	2024	9.79E-01	9.70E-01	9.07E-03	3.92E-01	FALSE	N/A
Percent of catastrophic-weather restorations made within 48 hours	2020	9.02E-01	7.97E-01	1.04E-01	2.53E-03	TRUE	High
	2021	7.99E-01	7.75E-01	2.42E-02	5.09E-01	FALSE	N/A
	2022	9.39E-01	9.59E-01	-2.05E-02	3.59E-01	FALSE	N/A
	2023	8.57E-01	8.42E-01	1.55E-02	6.63E-01	FALSE	N/A
	2024	9.58E-01	9.04E-01	5.40E-02	4.10E-02	TRUE	High
Percent of normal-weather restorations made within 8 hours	2020	9.52E-01	9.47E-01	5.63E-03	6.50E-01	FALSE	N/A
	2021	9.34E-01	9.34E-01	3.37E-04	9.80E-01	FALSE	N/A
	2022	9.45E-01	9.44E-01	2.02E-04	9.84E-01	FALSE	N/A
	2023	9.40E-01	9.33E-01	7.77E-03	5.28E-01	FALSE	N/A
	2024	9.46E-01	9.19E-01	2.71E-02	1.18E-01	FALSE	N/A
Percent of gray-sky weather restorations made within 24 hours	2020	9.34E-01	9.24E-01	1.00E-02	5.84E-01	FALSE	N/A
	2021	8.97E-01	8.82E-01	1.48E-02	5.05E-01	FALSE	N/A
	2022	8.97E-01	8.63E-01	3.38E-02	1.96E-01	FALSE	N/A
	2023	9.76E-01	9.26E-01	4.96E-02	5.50E-02	FALSE	N/A
	2024	9.45E-01	9.41E-01	3.45E-03	8.62E-01	FALSE	N/A

High-Percent-Minority-Percentile and Low Percent-Minority-Percentile Census Tracts

For High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts, the results of the binary difference-in-means t-test for each reliability metric and each year from 2020 through 2024 are shown in Table 8. Statistically significant differences in the mean reliability experienced by High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts are observed for many reliability metrics and years, including Unique Customers with an Interruption and Total Customer Interruptions; SAIDI and SAIFI, each including and excluding MEDs; CAIDI including MEDs; CEMI-4, -5, -7, and -10; and CELID-5 and -24. In contrast, the differences in mean reliability experienced by Low-Percent-Minority-

Percentile and High-Percent-Minority-Percentile census tracts in terms of CAIDI excluding MEDs, the percentage of normal-weather restorations made within 8 hours, and the percentage of gray-sky-weather restorations made within 24 hours are not statistically significant for any of the years included in this analysis. As Table 7 shows, when statistically significant differences in the mean reliability of these two groups are observed, it is almost always the High-Percent-Minority-Percentile census tracts that experience better average reliability. The lone exception to that pattern occurred in 2020, when the average percentage of catastrophic-weather restorations within 48 hours among Low-Percent-Minority-Percentile census tracts was greater than among High-Percent-Minority-Percentile census tracts.

Table 8. Comparison of census-tract-level reliability metrics for each year from 2020 through 2024 averaged for High-Percent-Minority-Percentile (High PM) census tracts and for Low-Percent-Minority-Percentile (Low PM) census tracts. Significance is assessed at $\alpha = 0.05$.

Reliability Metric	Year	Low PM Mean	High PM Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.13E+03	5.85E+02	5.48E+02	8.28E-10	TRUE	High PM
	2021	1.23E+03	6.83E+02	5.48E+02	1.12E-09	TRUE	High PM
	2022	1.12E+03	4.90E+02	6.35E+02	1.03E-11	TRUE	High PM
	2023	1.17E+03	5.26E+02	6.40E+02	9.26E-14	TRUE	High PM
	2024	1.11E+03	4.35E+02	6.77E+02	9.66E-14	TRUE	High PM
Total Customer Interruptions	2020	2.42E+03	9.32E+02	1.48E+03	1.35E-16	TRUE	High PM
	2021	2.89E+03	1.16E+03	1.73E+03	9.36E-16	TRUE	High PM
	2022	2.34E+03	7.88E+02	1.55E+03	4.28E-16	TRUE	High PM
	2023	2.51E+03	9.25E+02	1.58E+03	1.56E-14	TRUE	High PM
	2024	2.44E+03	7.32E+02	1.71E+03	4.04E-17	TRUE	High PM
SAIDI including MEDs	2020	5.17E+02	3.57E+02	1.60E+02	3.38E-02	TRUE	High PM
	2021	9.51E+02	3.66E+02	5.86E+02	1.01E-16	TRUE	High PM
	2022	4.56E+02	2.15E+02	2.41E+02	9.28E-09	TRUE	High PM
	2023	9.35E+02	2.70E+02	6.65E+02	1.16E-13	TRUE	High PM
	2024	4.88E+02	2.40E+02	2.48E+02	8.77E-07	TRUE	High PM
SAIDI excluding MEDs	2020	1.98E+02	1.27E+02	7.11E+01	1.62E-05	TRUE	High PM
	2021	2.42E+02	1.73E+02	6.88E+01	7.00E-03	TRUE	High PM
	2022	1.83E+02	1.34E+02	4.87E+01	3.27E-02	TRUE	High PM
	2023	1.81E+02	1.48E+02	3.32E+01	2.67E-01	FALSE	N/A
	2024	1.62E+02	1.19E+02	4.31E+01	1.73E-01	FALSE	N/A
SAIFI including MEDs	2020	1.34E+00	9.13E-01	4.26E-01	9.75E-06	TRUE	High PM
	2021	1.63E+00	1.15E+00	4.80E-01	2.07E-04	TRUE	High PM
	2022	1.28E+00	8.04E-01	4.76E-01	5.54E-05	TRUE	High PM
	2023	1.39E+00	9.60E-01	4.34E-01	2.86E-03	TRUE	High PM
	2024	1.33E+00	7.54E-01	5.74E-01	3.98E-05	TRUE	High PM
SAIFI excluding MEDs	2020	1.02E+00	6.68E-01	3.54E-01	8.69E-05	TRUE	High PM
	2021	1.08E+00	9.14E-01	1.62E-01	1.45E-01	FALSE	N/A
	2022	9.66E-01	7.12E-01	2.54E-01	1.31E-02	TRUE	High PM

Reliability Metric	Year	Low PM Mean	High PM Mean	Difference	*p*-value	Significant?	Better?
	2023	9.70E-01	8.67E-01	1.03E-01	4.24E-01	FALSE	N/A
	2024	9.03E-01	5.75E-01	3.28E-01	4.89E-03	TRUE	High PM
	2020	3.61E+02	4.52E+02	-9.17E+01	2.66E-01	FALSE	N/A
	2021	5.25E+02	3.51E+02	1.74E+02	6.77E-05	TRUE	High PM
CAIDI including MEDs	2022	3.48E+02	2.80E+02	6.84E+01	1.77E-02	TRUE	High PM
	2023	5.39E+02	2.70E+02	2.69E+02	7.41E-09	TRUE	High PM
	2024	3.46E+02	3.72E+02	-2.65E+01	5.08E-01	FALSE	N/A
	2020	1.90E+02	2.42E+02	-5.21E+01	1.21E-01	FALSE	N/A
	2021	2.12E+02	1.92E+02	2.01E+01	2.60E-01	FALSE	N/A
CAIDI excluding MEDs	2022	1.88E+02	1.96E+02	-7.89E+00	6.30E-01	FALSE	N/A
	2023	1.89E+02	1.83E+02	5.83E+00	6.96E-01	FALSE	N/A
	2024	1.81E+02	2.05E+02	-2.38E+01	1.52E-01	FALSE	N/A
	2020	9.39E-02	1.73E-02	7.66E-02	9.29E-21	TRUE	High PM
	2021	1.33E-01	3.77E-02	9.56E-02	1.25E-10	TRUE	High PM
CEMI-4	2022	9.46E-02	2.46E-02	7.00E-02	1.47E-09	TRUE	High PM
	2023	1.09E-01	3.95E-02	6.99E-02	3.11E-06	TRUE	High PM
	2024	1.09E-01	4.37E-02	6.58E-02	3.00E-04	TRUE	High PM
	2020	4.76E-02	2.85E-03	4.48E-02	2.68E-31	TRUE	High PM
	2021	7.43E-02	1.15E-02	6.28E-02	1.69E-19	TRUE	High PM
CEMI-5	2022	4.70E-02	1.36E-02	3.34E-02	6.45E-07	TRUE	High PM
	2023	5.59E-02	1.11E-02	4.48E-02	2.30E-09	TRUE	High PM
	2024	6.20E-02	1.53E-02	4.67E-02	4.62E-07	TRUE	High PM
	2020	1.25E-02	3.03E-04	1.22E-02	6.13E-13	TRUE	High PM
	2021	2.05E-02	4.54E-05	2.04E-02	3.52E-21	TRUE	High PM
CEMI-7	2022	1.02E-02	1.05E-03	9.19E-03	3.98E-10	TRUE	High PM
	2023	1.59E-02	1.84E-03	1.40E-02	5.49E-08	TRUE	High PM
	2024	1.94E-02	1.29E-03	1.81E-02	1.21E-15	TRUE	High PM
	2020	2.88E-03	0.00E+00	2.88E-03	8.41E-03	TRUE	High PM
	2021	2.18E-03	0.00E+00	2.18E-03	5.08E-07	TRUE	High PM
CEMI-10	2022	1.41E-03	0.00E+00	1.41E-03	4.41E-03	TRUE	High PM
	2023	2.27E-03	0.00E+00	2.27E-03	8.83E-06	TRUE	High PM
	2024	4.70E-03	0.00E+00	4.70E-03	3.79E-05	TRUE	High PM
	2020	2.73E-01	2.17E-01	5.63E-02	2.02E-01	FALSE	N/A
	2021	3.98E-01	2.35E-01	1.63E-01	5.30E-05	TRUE	High PM
CELID-5	2022	2.76E-01	1.96E-01	8.02E-02	4.36E-02	TRUE	High PM
	2023	3.57E-01	1.80E-01	1.77E-01	1.28E-04	TRUE	High PM
	2024	2.98E-01	1.93E-01	1.05E-01	6.95E-03	TRUE	High PM
	2020	8.06E-02	5.48E-02	2.58E-02	2.95E-01	FALSE	N/A
	2021	1.63E-01	4.90E-02	1.14E-01	3.33E-13	TRUE	High PM
CELID-24	2022	6.12E-02	2.80E-02	3.33E-02	3.07E-03	TRUE	High PM
	2023	1.68E-01	5.45E-02	1.13E-01	3.40E-04	TRUE	High PM

Reliability Metric	Year	Low PM Mean	High PM Mean	Difference	*p*-value	Significant?	Better?
	2024	7.16E-02	4.87E-02	2.29E-02	7.85E-02	FALSE	N/A
Percent of all-weather restorations made within 36 hours	2020	9.71E-01	9.40E-01	3.08E-02	2.31E-01	FALSE	N/A
	2021	9.44E-01	9.60E-01	-1.55E-02	1.82E-01	FALSE	N/A
	2022	9.78E-01	9.89E-01	-1.08E-02	8.17E-03	TRUE	High PM
	2023	9.30E-01	9.85E-01	-5.57E-02	5.14E-07	TRUE	High PM
	2024	9.78E-01	9.61E-01	1.69E-02	2.20E-01	FALSE	N/A
Percent of catastrophic-weather restorations made within 48 hours	2020	8.97E-01	7.34E-01	1.63E-01	1.57E-02	TRUE	Low PM
	2021	7.98E-01	7.50E-01	4.83E-02	4.27E-01	FALSE	N/A
	2022	9.39E-01	1.00E+00	-6.10E-02	1.04E-16	TRUE	High PM
	2023	8.55E-01	8.89E-01	-3.39E-02	6.11E-01	FALSE	N/A
	2024	9.55E-01	8.98E-01	5.70E-02	1.36E-01	FALSE	N/A
Percent of normal-weather restorations made within 8 hours	2020	9.52E-01	9.32E-01	2.08E-02	4.83E-01	FALSE	N/A
	2021	9.34E-01	9.48E-01	-1.38E-02	2.80E-01	FALSE	N/A
	2022	9.45E-01	9.30E-01	1.47E-02	4.14E-01	FALSE	N/A
	2023	9.40E-01	9.24E-01	1.65E-02	4.08E-01	FALSE	N/A
	2024	9.46E-01	8.81E-01	6.45E-02	5.66E-02	FALSE	N/A
Percent of gray-sky weather restorations made within 24 hours	2020	9.34E-01	9.15E-01	1.85E-02	5.76E-01	FALSE	N/A
	2021	8.98E-01	8.35E-01	6.31E-02	9.98E-02	FALSE	N/A
	2022	8.97E-01	8.09E-01	8.80E-02	8.72E-02	FALSE	N/A
	2023	9.73E-01	9.36E-01	3.63E-02	3.50E-01	FALSE	N/A
	2024	9.43E-01	9.74E-01	-3.11E-02	1.11E-01	FALSE	N/A

Summary of Comparisons of Average Reliability Among Groups of Census Tracts

Comparisons of the average reliability in each year from 2020 through 2024 among EJ and Non-EJ; Urban and Rural; Low-Income and High-Income; and High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts show that when statistically significant differences in the average reliability of each pair of groups exist, it is consistently the EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts that have better average reliability than their counterparts. The metrics by which EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts experienced better average reliability include SAIDI and SAIFI, excluding and including MEDs, indicating that customers in these census tracts had shorter and less frequent interruptions on average than customers in Non-EJ, Rural, High-Income, and Low-Percent-Minority-Percentile census tracts, respectively. In some years, statistically significant differences in CAIDI were also observed between these groups and confirmed that EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts tend to experience shorter average restoration times than Non-EJ, Rural, High-Income, and Low-Percent-Minority-Percentile census tracts, respectively.

EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts also experienced better average reliability in terms of CEMI-4, -5, -7, and -10 and CELID-5 and -24 than Non-EJ, Rural, High-Income and Low-Percent-Minority-Percentile census tracts, respectively. This

indicates that smaller proportions of customers in EJ, Urban, Low-Income, and High-Percent-Minority-Percentile areas experienced multiple sustained interruptions and long interruption durations than in Non-EJ, Rural, High-Income, and Low-Percent-Minority Percentile areas, respectively.

No statistically significant differences in the average percentage of normal-weather restorations within 8 hours were observed in any year from 2020 through 2024 among the four pairs of census tract groups considered. No statistically significant differences in the average percentage of catastrophic-weather restorations in 48 hours were observed among EJ and non-EJ and Urban and Rural groups of census tracts in any year from 2020 through 2024. However, statistically significant differences were observed among Low- and High-Income census tracts in 2020 and in 2024, with High-Income census tracts having a higher average percentage of catastrophic-weather restorations in 48 hours than Low-Income census tracts in both years. Statistically significant differences were also observed among Low-Percent-Minority-Percentile and High-Percent-Minority-Percentile census tracts in 2020 and 2022, with Low-Percent-Minority-Percentile census tracts having a higher average percentage of catastrophic-weather restorations in 48 hours than High-Percent-Minority-Percentile census tracts, and the opposite occurring in 2022.

Census-Tract-Level Reliability Regression Results

To assess the relationships between the demographic characteristics of different census tracts and the electric reliability experienced by customers within those census tracts, we fit mixed-effects linear regression models considering both county-level and year fixed effects to each of the 18 reliability metrics tabulated for 2010 census tracts from 2020 through 2024. The following subsections describe two sets of census-tract-level reliability regression models: in the first set, MiEJScreen Overall Score was included as an independent variable; and in the second set of regression models, it was replaced by Percent Minority Percentile. We fit the second set of regression models since the MiEJScreen Overall Score combines many different variables into a single indicator and may therefore obscure relationships between individual indicators (such as the Percent Minority Percentile of a census tract) and reliability.

Census-Tract-Level Reliability Regression Results Considering MiEJScreen Overall Score

For each of the 18 reliability metrics, which were considered separately as dependent variables, we fit five different models, for a total of 90 regression models. The independent variables included in each of those five models are listed below and were selected based in part on those considered by Pradhan and Chan (2024).[29]

1. MiEJScreen Overall Score;
2. MiEJScreen Overall Score and Poverty;
3. MiEJScreen Overall Score and Median Household Income past 12 months (in $10,000 increments);

[29] Pradhan and Chan (2024), p8.

4. MiEJScreen Overall Score and Population Density (in increments of 100 people per square mile); and
5. MiEJScreen Overall Score, Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden.

Table 9 shows the values of the regression coefficients for each independent variable in each of the five models for SAIDI excluding MEDs. As Table 9 shows, the MiEJScreen Overall Score has a statistically significant, negative correlation with SAIDI excluding MEDs in each of the five models fitted. In other words, as the MiEJScreen Overall Score of a census tract increases, its reliability as measured by SAIDI excluding MEDs tends to improve when all other variables are held constant. In Model 1, in which the MiEJScreen Overall Score is the only independent variable, a one percentage point increase in the MiEJScreen Overall Score is associated with a 1.49 minute decrease in SAIDI excluding MEDs when county and year factors are held constant. In Model 5 – in which controls are added for Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden – a one percentage point increase in the MiEJScreen Overall Score is associated with a 1.36 minute decrease in SAIDI excluding MEDs when all other independent variables, as well as county and year factors, are held constant.

The coefficients of the other predictors in Model 5 that are statistically significant can be interpreted as follows when all other independent variables, county, and year factors are held constant:

- A one percentage point increase in Poverty is associated with a 0.4 minute increase in SAIDI excluding MEDs;
- An increase in Population Density of 1000 people per square mile is associated with a 0.9 minute decrease in SAIDI excluding MEDs;
- A one percentage point increase in Percent Unemployed is associated with an approximately 3 minute increase in SAIDI excluding MEDs; and
- A one percentage point increase in Housing Burden is associated with a 0.4 minute decrease in SAIDI excluding MEDs.

The average value of SAIDI excluding MEDs considering all census tracts in Consumers' service territory ranges from approximately 160 minutes to 240 minutes from 2020 through 2024. While the increases in SAIDI excluding MEDs associated with one percentage point increases of different independent variables in Model 5 may seem small in comparison to those average values, a ten-percentage point increase in Percent Unemployed is associated with a 29 minute increase in SAIDI excluding MEDs when all other variables are held constant. The range of values in Percent Unemployed within Consumers' service territory ranges from 0 to 49, so larger percentage point increases are not unforeseeable.

Table 10 shows the values of the regression coefficients for each independent variable in each of the five models for SAIFI excluding MEDs. As in the models for SAIDI excluding MEDs, the MiEJScreen Overall Score has a statistically significant, negative correlation with SAIFI excluding MEDs in each of the five models fitted: that is, as a census tract's MiEJScreen Overall Score increases, its reliability tends to improve when all other variables are held constant.

The nature of the relationship between MiEJScreen Overall Score and reliability is the same – statistically significant ($p < 0.05$) and negatively correlated – for the following reliability metrics: SAIDI including MEDs; SAIFI including MEDs; CAIDI including or excluding MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Unique Customers with an Interruption; and Total Customer Interruptions (regression results for these and all other reliability metrics not shown here are tabulated in Appendix A). In other words, as the MiEJScreen Overall Score of a census tract increases, its reliability tends to improve when all other variables are held constant. The correlation between MiEJScreen Overall Score and the percentage of all-weather restorations made within 36 hours is statistically significant ($p < 0.05$) and positive, indicating that as the MiEJScreen Overall Score of a census tract increases, the reliability of the census tract in terms of this metric improves when all other variables are held constant. The correlation between MiEJScreen Overall Score and reliability is not statistically significant at the $p < 0.05$ level in any of the models considered when reliability is measured in terms of CEMI-10, the percentage of normal-weather restorations made within 8 hours, the percentage of gray-sky-weather restorations made within 24 hours, or the percentage of catastrophic-weather restorations made within 48 hours. Taken together, these results show no evidence that census tracts with higher MiEJScreen Overall Scores tend to have worse reliability than other census tracts.

Table 9. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI excluding MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI excluding MEDs	1	2	3	4	5
MiEJScreen Overall Score	-1.49e+00*** (1.31e-01)	-1.63e+00*** (1.73e-01)	-1.62e+00*** (1.98e-01)	-1.09e+00*** (1.62e-01)	-1.36e+00*** (2.18e-01)
Poverty	-	1.81e-01 (1.40e-01)	-	-	4.38e-01* (2.00e-01)
Median Household Income past 12 months	-	-	-1.89e+00 (2.15e+00)	-	1.28e+00 (2.56e+00)
Population Density	-	-	-	-8.21e-01*** (1.97e-01)	-8.57e-01*** (2.04e-01)
Percent Unemployed	-	-	-	-	2.91e+00*** (6.52e-01)
Housing Burden	-	-	-	-	-4.03e-01* (1.67e-01)

Table 10. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI excluding MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI excluding MEDs	1	2	3	4	5
MiEJScreen Overall Score	-5.72e-03*** (4.99e-04)	-6.65e-03*** (6.61e-04)	-6.55e-03*** (7.53e-04)	-3.93e-03*** (6.18e-04)	-5.49e-03*** (8.29e-04)
Poverty	-	1.15e-03* (5.36e-04)	-	-	1.71e-03* (7.62e-04)
Median Household Income past 12 months	-	-	-1.22e-02 (8.21e-03)	-	4.04e-03 (9.77e-03)
Population Density	-	-	-	-3.68e-03*** (7.55e-04)	-4.13e-03*** (7.80e-04)
Percent Unemployed	-	-	-	-	1.03e-02*** (2.49e-03)
Housing Burden	-	-	-	-	-6.82e-04 (6.38e-04)

Census-Tract-Level Reliability Regression Considering Percent Minority Percentile

The independent variables included in each of the five models fitted for each reliability metric are listed below:

1. Percent Minority Percentile;
2. Percent Minority Percentile and Poverty;
3. Percent Minority Percentile and Median Household Income past 12 months (in $10,000 increments);
4. Percent Minority Percentile and Population Density (in increments of 100 people per square mile); and
5. Percent Minority Percentile, Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden.

Table 11 shows that Percent Minority Percentile has a statistically significant, negative correlation with SAIDI excluding MEDs in each of the five models that were fitted. That is, increases in the Percent Minority Percentile of a census tract are associated with improving reliability when all other independent variables, as well as county and year factors, are held constant. In Model 1, a one percentage point increase in the Percent Minority Percentile of a census tract is associated with a decrease of 1.2 minutes in the census tract's SAIDI excluding

MEDs. In Model 5, which includes controls for all the other independent variables considered, a one percentage point increase in the Percent Minority Percentile of a census tract is associated with a decrease of approximately 1 minute in the census tract's SAIDI excluding MEDs when all other variables are held constant. The coefficients of the other predictors in Model 5 can be interpreted as follows when all other independent variables, as well as county and year factors, are held constant:

- A one percentage point increase in Poverty is associated with a 0.8 minute increase in SAIDI excluding MEDs;
- A $10,000 increase in Median Household Income past 12 months is associated with a 0.9 minute increase in SAIDI excluding MEDs;
- An increase in Population Density of 100 people per square mile is associated with an approximately 1 minute decrease in SAIDI excluding MEDs;
- A one percentage point increase in Percent Unemployed is associated with a 3.1 minute increase in SAIDI excluding MEDs; and
- A one percentage point increase in Housing Burden is associated with a 0.4 minute decrease in SAIDI excluding MEDs.

As discussed in the previous subsection, while the increases in SAIDI excluding MEDs associated with one percentage point increases of different independent variables in Model 5 may seem small in comparison to those average values, a ten percentage point increase in Percent Unemployed is associated with a 31 minute increase in SAIDI excluding MEDs when all other variables are held constant. The statistically significant, positive correlation between Percent Unemployed and reliability persists for SAIDI including MEDs, as shown in Table 12: a one percentage point increase in Percent Unemployed is associated with a 9 minute increase in SAIDI including MEDs when all other independent variables, as well as county and year factors, are held constant. In other words, as Percent Unemployed for a census tract increases, reliability tends to worsen.

The statistically significant, negative correlation that was observed between Percent Minority Percentile and SAIDI excluding MEDs was also observed between Percent Minority Percentile and SAIDI including MEDs, as shown in Table 12. When all else is held constant, an increasing Percent Minority Percentile is associated with improving reliability at the census tract level. The larger coefficients for Percent Minority Percentile in the regression models for SAIDI including MEDs reflect that SAIDI including MEDs has a greater average value than SAIDI excluding MEDs, as shown in Table 3.

The nature of the relationship between Percent Minority Percentile and reliability is the same – statistically significant ($p < 0.05$) and negatively correlated – for Models 1 through 5 for the following reliability metrics: SAIFI excluding or including MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Unique Customers with an Interruption; and Total Customer Interruptions (regression results for these and all other metrics not shown here are tabulated in Appendix A). In other words, as the Percent Minority Percentile of a census tract increases, its reliability – as measured by those metrics – tends to improve when all other variables are held constant.

For both CAIDI excluding MEDs and CAIDI including MEDs, Percent Minority Percentile is not statistically significant at the $p < 0.05$ level in Model 5, but is statistically significant and

negatively correlated with CAIDI in Models 1 through 4. That is, when controls are added simultaneously for Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden, the relationship between Percent Minority Percentile and CAIDI excluding or including MEDs is no longer statistically significant.

The correlation between Percent Minority Percentile and the percentage of all-weather restorations made within 36 hours is statistically significant ($p < 0.05$) and positive only when Percent Minority Percentile is the only independent variable, suggesting that Percent Minority Percentile differences in restoration percentages can be explained by the additional demographic and economic characteristics added as controls in Models 2 through 5. The correlation between Percent Minority Percentile and reliability is not statistically significant at the $p < 0.05$ level in any of the models considered when reliability is measured in terms of the percentage of normal-weather restorations made within 8 hours, the percentage of gray-sky-weather restorations made within 24 hours, or the percentage of catastrophic-weather restorations made within 48 hours.

Taken together, these results show no evidence that census tracts with higher Percent Minority Percentile values tend to have worse reliability than other census tracts.

Table 11. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI excluding MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI excluding MEDs	1	2	3	4	5
Percent Minority Percentile	-1.21e+00*** (1.13e-01)	-1.25e+00*** (1.47e-01)	-1.02e+00*** (1.33e-01)	-8.45e-01*** (1.32e-01)	-1.06e+00*** (1.55e-01)
Poverty	-	6.02e-02 (1.38e-01)	-	-	7.73e-01*** (2.06e-01)
Median Household Income past 12 months	-	-	4.64e+00** (1.67e+00)	-	8.78e+00*** (2.28e+00)
Population Density	-	-	-	-9.91e-01*** (1.86e-01)	-9.47e-01*** (1.98e-01)
Percent Unemployed	-	-	-	-	3.12e+00*** (6.54e-01)
Housing Burden	-	-	-	-	-3.94e-01* (1.67e-01)

Table 12. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI including MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI including MEDs	1	2	3	4	5
Percent Minority Percentile	-6.07e+00*** (5.29e-01)	-5.65e+00*** (6.85e-01)	-4.67e+00*** (6.18e-01)	-4.06e+00*** (6.16e-01)	-4.60e+00*** (7.23e-01)
Poverty	-	-6.22e-01 (6.42e-01)	-	-	2.39e+00* (9.63e-01)
Median Household Income past 12 months	-	-	3.39e+01*** (7.78e+00)	-	4.88e+01*** (1.07e+01)
Population Density	-	-	-	-5.48e+00*** (8.71e-01)	-5.13e+00*** (9.28e-01)
Percent Unemployed	-	-	-	-	9.01e+00** (3.07e+00)
Housing Burden	-	-	-	-	-5.47e-02 (7.80e-01)

Summary of Census-Tract-Level Reliability Regression Results

Regression models of census-tract-level reliability as a function of MiEJScreen Overall Score and other economic and demographic variables indicate that increasing MiEJScreen Overall Score tends to be associated with improving reliability, when a statistically significant correlation between the two exists. This observation holds true for SAIDI including MEDs; SAIFI including MEDs; CAIDI including or excluding MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Unique Customers with an Interruption; and Total Customer Interruptions. Furthermore, this observation is consistent with the results of the binary difference-in-means t-test for EJ and Non-EJ census tracts, which indicated that EJ census tracts experience better average reliability than Non-EJ census tracts.

Increasing Population Density also tends to be associated with improving reliability, e.g., in terms of SAIFI excluding and including MEDs (Tables A1 and A2, respectively); CAIDI including MEDs (Table A4); CELID-5 and -24 (Tables A5 and A6); and CEMI-4, -5, and -7 (Tables A7, A8, and A9). This correlation may reflect redundancy in the electric distribution system in more densely populated areas that improves reliability. Increasing Population Density does not have statistically significant correlations with percentages of restorations made under different weather conditions (Tables A11 through A15); this result is consistent with the results of the binary difference-in-means t-tests that did not find statistically significant differences in

the average percentages of restorations made under different weather conditions among Urban and Rural census tracts for most years considered (Table 6).

In contrast, increasing Poverty and increasing Percent Unemployed have statistically significant correlations with worsening reliability, in terms of SAIDI excluding and including MEDs (Table 9 and Table 10) as well as SAIFI excluding and including MEDs (Tables A1 and A2). Census tracts with higher poverty and unemployment rates tend to have longer and more frequent outages when all other variables, as well as county and year effects, are held constant. This observation seems to contrast with the comparison of average reliability of Low-Income and High-Income census tracts previously discussed, which found that Low-Income census tracts have better reliability on average than High-Income census tracts. This difference may be explained by the differing levels of granularity of the two analyses: the regression analysis includes controls for multiple demographic characteristics, while the binary difference-in-means t-test considers only one way of characterizing census tracts.

Regression models of census-tract-level reliability as a function of Percent Minority Percentile and other economic and demographic variables indicate that increasing Percent Minority Percentile – that is, an increasing proportion of a census tract's population comprised of racial/ethnic minority groups – is associated with better reliability, when a statistically significant relationship between the two exists. In Model 5, when controls are included for Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden, a statistically significant correlation between Percent Minority Percentile and improving reliability is observed for SAIDI excluding and including MEDs (Table 11 and Table 12); SAIFI excluding and including MEDs (Tables A17 and A18); and CEMI-4, -5, and -7 (Tables A23 through A25). This result is consistent with the results of the binary difference-in-means t-tests that found statistically significant differences in the average reliability of High-Percent-Minority-Percentile census tracts and Low-Percent-Minority-Percentile census tracts, with the former consistently experiencing better reliability than the latter.

Feeder-Level Reliability Regression Analysis Results

For a given measure of feeder reliability (SAIDI and SAIFI, each with and without MEDs), we fit six different mixed-effects linear regression models to feeder and demographic characteristics in order to determine: (1) how much of the variation in reliability can be attributed to differences between feeders; and (2) to which feeder or population-level characteristics the variation in reliability could be attributed. A total of twenty-four mixed-effects linear regression models (four feeder reliability metrics times six models) were therefore fitted.

Each of the six mixed-effects linear regression models included different independent variables and fixed effects. Two categories of independent variables were considered: (1) feeder characteristics; and (2) demographic characteristics of the census tracts served by a feeder. The feeder characteristics included in some of the six mixed-effects linear regression models were:

- Customers per Primary Line Mile;
- Mean Canopy Cover Percentage;
- Open Wire Secondary Miles;
- Primary Miles;

- Primary Underground Percentage;
- Voltage, as a categorical variable with the most common (4.8/8.32 kV Wye Grounded) as the reference value; and
- Years Since Last Trim < 7, which was a binary variable with a value of 1 if the vegetation near the feeder had been trimmed in the past seven years and 0 otherwise.

Demographic characteristics were included as binary variables in some of the six mixed-effects linear regression models. A feeder was considered to serve a particular type of census tract – as defined by a particular demographic characteristic – if any part of its length overlapped with any census tract of that type, as previously discussed. The demographic characteristics included in some of the six mixed-effects linear regression models are listed below; all take a value of 1 if the feeder serves the type of census tract described and take a value of 0 otherwise:

- Serves an EJ census tract;
- Serves an Urban census tract;
- Serves a Low-Income census tract; and
- Serves a High-Percent-Minority-Percentile census tract.

The six types of mixed-effects linear regression models that we fit are as follows:

1. Intercept-only: This model serves as a baseline for comparison. It provides an overall mean reliability across all feeders across all years;
2. Feeder characteristic fixed effects: This model quantifies the effect that each feeder characteristic has on reliability;
3. Year fixed effects: This model quantifies potential time-dependent effects on feeder reliability;
4. Feeder characteristic and year fixed effects: This model quantifies the effect of each feeder characteristic, considering any potential time-based fixed effects;
5. Demographic fixed effects: This model includes only demographic characteristics and quantifies their effect on feeder reliability; and
6. Combined effects: This model includes both feeder and demographic characteristics and accounts for any potential time-based fixed effects.

Table 13 shows the AIC and BIC for each model and reliability metric. Across all metrics, Model 6 has the best score in terms of AIC, with Model 4 a close second. Model 4 has the best score in terms of BIC (except for SAIFI without MEDs, where Model 2 has the best BIC) with Model 6 a close second. As BIC penalizes a model more severely for including more parameters, the feeder-characteristic only models having a better BIC than models including demographic characteristics corroborates some of the findings detailed in the following subsections that suggest that feeder characteristics are better predictors of feeder reliability than a combination of feeder and demographic characteristics.

Table 13. AIC and BIC values for six mixed-effects linear regression models for each of four feeder-level reliability metrics (SAIDI and SAIFI, each excluding and including MEDs). Values in bold indicate the best score for each criterion.

	SAIDI w/o MEDs		SAIDI w/ MEDs		SAIFI w/o MEDs		SAIFI w/ MEDs	
Model	AIC	BIC	AIC	BIC	AIC	BIC	AIC	BIC
1	1.334E+05	1.334E+05	1.651E+05	1.651E+05	2.711E+04	2.713E+04	3.243E+04	3.245E+04
2	1.326E+05	1.328E+05	1.645E+05	1.646E+05	2.632E+04	**2.644E+04**	3.141E+04	3.154E+04
3	1.333E+05	1.334E+05	1.647E+05	1.648E+05	2.710E+04	2.715E+04	3.232E+04	3.237E+04
4	1.326E+05	**1.327E+05**	1.641E+05	**1.642E+05**	2.630E+04	2.646E+04	3.130E+04	**3.146E+04**
5	1.331E+05	1.331E+05	1.648E+05	1.648E+05	2.686E+04	2.691E+04	3.209E+04	3.214E+04
6	**1.326E+05**	1.328E+05	**1.641E+05**	1.643E+05	**2.630E+04**	2.649E+04	**3.130E+04**	3.149E+04

Assessing Between-Feeder and Within-Feeder Variability

Figure 1 plots the ICC for each model to show how the explained variance changes with the introduction of various predictors. The intercept-only models suggest there is a certain level of baseline variability that is attributed to within-feeder variance and not differences between feeders. The ICC values for the intercept-only models of SAIDI without MEDs, SAIDI with MEDs, SAIFI without MEDs, and SAIFI with MEDs are 0.24, 0.14, 0.25, and 0.3, respectively. These ICC values indicate that 76%, 86%, 75%, and 70% of the existing variability in these reliability metrics is due to within-feeder variance over time rather than to differences between feeders. The remaining variability, indicated by the ICC value, is differences between feeders that additional predictors may help explain.

For all four reliability metrics, Model 2, which includes only feeder characteristic effects, has a lower ICC than Model 5, which includes only demographic characteristic effects. Because ICC values closer to 0 indicate that within-feeder variance accounts for more of the remaining unexplained variance in the model than between-feeder variance, Model 2 having a lower ICC than Model 5 indicates that feeder characteristics explain more of the between-feeder variability than demographic characteristics. For example, for SAIDI without MEDs, the ICC decreasing from 0.24 with Model 1 (the intercept-only model) to 0.13 with Model 2 (in which only feeder characteristics are included) means that the feeder characteristics explained some of the between-feeder variance that was previously unexplained in Model 1. Model 5 (in which only demographic characteristics are included) has an ICC of 0.19, meaning it explained some between-feeder variability, but not as much as the feeder characteristics included in Model 2.

Also notable is the difference in baseline reliability for each metric depending on if MEDs are considered. For SAIDI and SAIFI, approximately 24-25% of the variability can be attributed to between-feeder differences at baseline when MEDs are not considered. When MEDs are considered, the variability due to between-feeder differences decreases to 14-15% for SAIDI, while for SAIFI, this increases to 30% that can be attributed to between-feeder variability. This indicates that SAIFI is more sensitive to differences between feeders than SAIDI when MEDs are included.

The year fixed effect does not contribute to between-feeder variation. Without MEDs, there is no change in the ICC when year fixed effects are included in the models. With MEDs, there is a one percentage point increase in the ICC value when year fixed effects are included. Year-to-year variation appears to primarily be a driver for within-feeder variability as opposed to between-feeder. That is, variability in reliability within a feeder over time is more substantial than variability between feeders when considering potential yearly effects. The inclusion of the year fixed effect did not help explain additional between-feeder variability based on the ICC value relative to the intercept-only model.

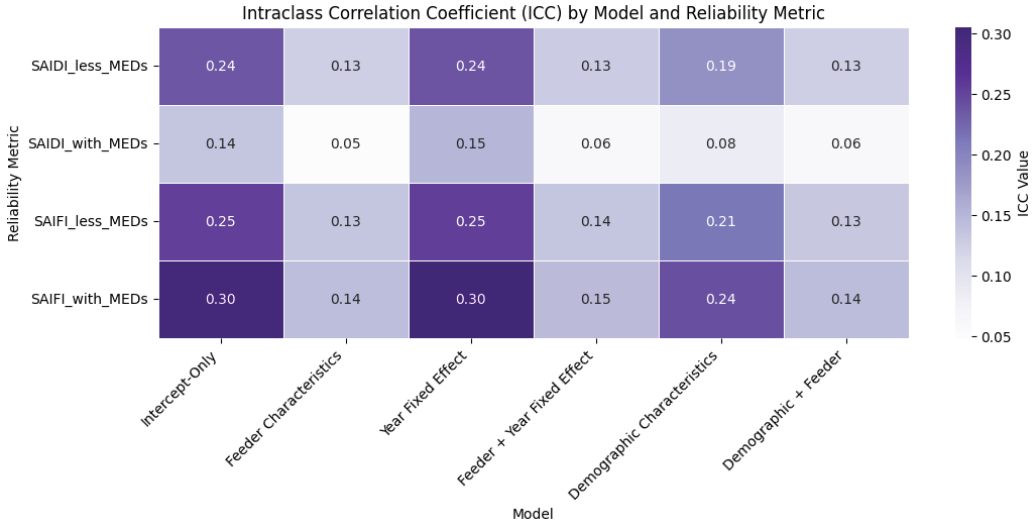


Figure 1. Heatmap of Intraclass Correlation Coefficient (ICC) values for each reliability metric and feeder-level reliability regression model.

Assessing the Impact of Feeder and Population Characteristics on Reliability

For each model, the coefficients and p-values for each independent variable are estimated and shown in Table 14 through Table 17. Figure 2 through Figure 5 plot the coefficients from the combined effects model (Model 6). The combined effect model provides estimates for all variables of interest, so only the coefficients for this model are presented in the plots. The Serves Urban, Serves Low Income, Serves High Percent Minority Percentile, Serves EJ, and Years Since Last Trim < 7 predictors are binary variables, so their coefficients are the difference in reliability between the two groups they represent. The coefficients associated with the different voltages refer to the difference in mean reliability between the voltage of interest and the reference voltage. For the demographic characteristics, only Serves Urban is significant for SAIDI (with and without MEDs), and only EJ tract is significant for SAIFI (with and without MEDs). The urban/rural indicator has a negative coefficient, indicating tracts classified as urban may experience reduced duration of interruptions compared to rural tracts. While Serves EJ has a positive coefficient, indicating that EJ communities may experience more frequent outages. Classification as low income and high minority tract are not significant at the 0.05 level for any metric. The following sections detail the results for each reliability metric and the 6 fitted models.

SAIDI excluding MEDs

For SAIDI excluding MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 2, while Table 14 reports the coefficient, p-value, and standard error for each independent variable in Models 1 through 6. As Figure 2 and Table 14 show, Voltage can have a large and statistically significant correlation with SAIDI excluding MEDs: 11.0 kV Delta, 12.0 kV Delta, 14.4 kV Delta, 14.4/24.9 kV Wye Grounded, and 4.8 kV Delta configurations all have greater mean SAIDI excluding MEDs than that of the reference voltage (4.8/8.32 kV Wye Grounded). The coefficients indicate that the mean SAIDI excluding MEDs of feeders can range from approximately 72 minutes (14.4/24.9 kV Wye Grounded) to 382 minutes (4.8 kV Delta) longer than that of the reference voltage when all other variables are held constant.

Figures B1 through B10 show the census tracts served by feeders of each voltage: Figure B10 shows that area served by 14.4 kV Delta feeders is relatively limited (as noted in Table B1, these feeders make up about 1% of Consumers' distribution feeders) and outside of city centers. Figure B5 shows that the area served by 4.8 kV Delta feeders, which make up less than 1% of Consumers' distribution feeders, is even smaller. The limited presence of Delta feeders within Consumers' distribution system – they account for less than 5% of feeders by count – and their limited spatial extents reflect that these feeders were part of smaller municipal utilities acquired by Consumers over time. Feeders with Delta configurations having longer average outage durations than the reference voltage, which is Wye Grounded, may also reflect that those feeders tend to be older than those at the reference voltage; data on feeder age was not available and therefore could not be included in the present study. Figure B3 shows the area served by 14.4/24.9 kV Wye Grounded feeders, which account for approximately 14% of distribution feeders by count. As previously noted, 14.4/24.9 kV Wye Grounded feeders tend to have longer outage durations, in terms of SAIDI excluding MEDs, than feeders at the reference voltage when all other variables are held constant. These feeders tend to be outside city centers and may therefore require more time to restore when interrupted.

All other feeder characteristics included in Model 6 have statistically significant correlations with SAIDI excluding MEDs and can be interpreted as follows, when all other variables are held constant:

- Years Since Last Trim < 7: Vegetation in proximity to a feeder having been trimmed in the last 7 years is correlated with an approximately 26 minute decrease in SAIDI excluding MEDs.
- Primary Underground Percentage: A one percentage-point increase in Primary Underground Percentage is correlated with a 0.9 minute decrease in SAIDI excluding MEDs.
- Customers per Primary Line Mile: An increase of 1 customer per primary line mile is associated with a 0.2 minute decrease in SAIDI excluding MEDs.
- Open Wire Secondary Miles: Every one-mile increase in Open Wire Secondary Miles is associated with a 3.9 minute decrease in SAIDI excluding MEDs.
- Mean Canopy Cover Percentage: A one percentage-point increase in Mean Canopy Cover Percentage is associated with a 3.7 minute increase in SAIDI excluding MEDs.
- Primary Miles: Every one-mile increase in Primary Miles is associated with a 1.4 minute increase in SAIDI excluding MEDs.

The signs of these correlations between feeder characteristics largely accord with our physical understanding of the distribution system. For example, as the amount of nearby vegetation increases, reliability tends to decrease, in terms of average outage duration. Similarly, as the length of a feeder increases, average outage duration tends to increase, which may reflect the time required to locate and repair faults. However, increases in Open Wire Secondary Miles being correlated with shorter outage durations (improving reliability) is counterintuitive, and it is unclear why this should be the case.

Of the population characteristics included in Model 6, only Serves Urban has a statistically significant correlation with SAIDI excluding MEDs: a feeder serving an Urban census tract is associated with a 22 minute decrease in SAIDI excluding MEDs when all other variables are held constant, which may reflect how increased redundancy in the distribution system in more densely populated areas reduces average outage durations. Whether a feeder serves EJ, Low-Income, or High-Percent-Minority-Percentile census tracts is not statistically significant in Models 5 or 6 for SAIDI excluding MEDs.

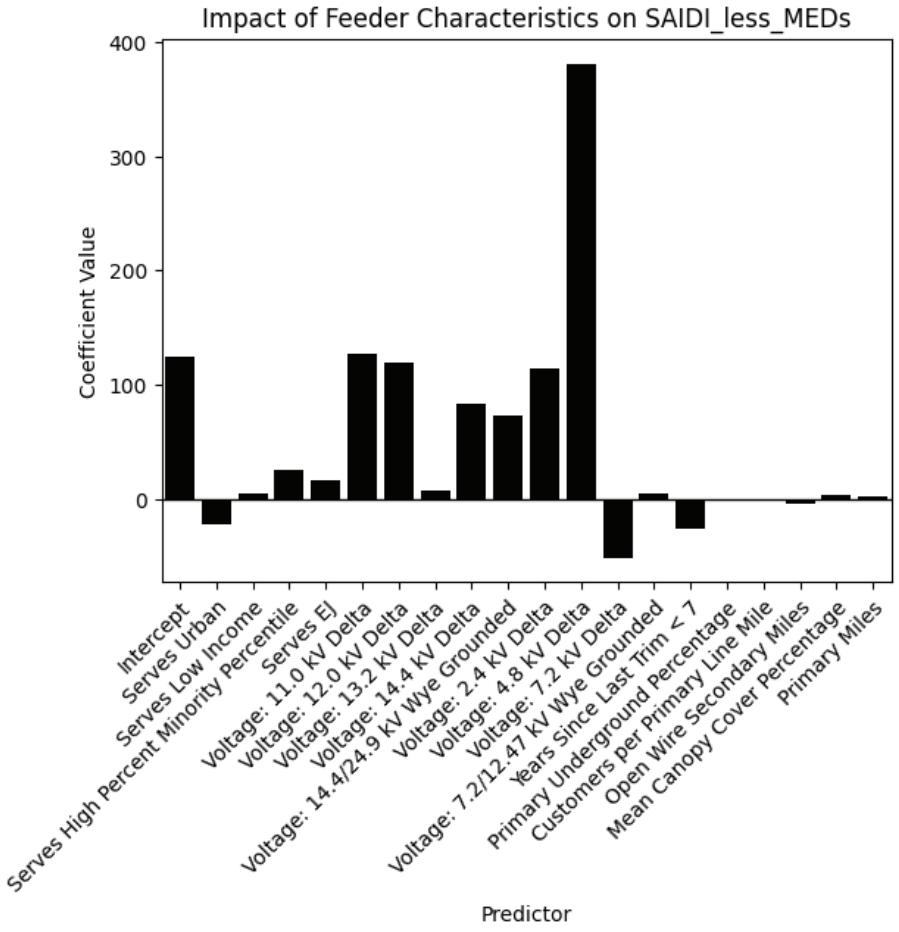


Figure 2. Regression coefficients for Model 6 (including feeder characteristics, population characteristics, and year fixed effects) of SAIDI excluding MEDs.

Table 14. Mixed-effects linear regression models for SAIDI excluding MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the p < 0.05 level.

Model:	1	2	3	4	5	6
Intercept	196.532*	129.932*	193.210*	123.136*	256.360*	124.794*
	(3.648)	(9.971)	(5.757)	(10.860)	(4.733)	(11.162)
Serves Urban					-120.190*	-21.982*
					(7.215)	(8.980)
Serves Low Income					-6.238	4.491
					(10.551)	(9.797)
Serves High Percent Minority Percentile					10.671	25.028
					(17.786)	(15.847)
Serves EJ					-1.738	15.647
					(10.867)	(10.686)
Voltage: 11.0 kV Delta		129.372*		129.474*		126.681*
		(37.521)		(37.502)		(37.420)
Voltage: 12.0 kV Delta		125.050*		123.925*		119.675*
		(57.660)		(57.632)		(57.518)
Voltage: 13.2 kV Delta		13.590		12.673		7.183
		(45.670)		(45.648)		(45.589)
Voltage: 14.4 kV Delta		85.759*		85.116*		82.999*
		(30.919)		(30.904)		(30.816)
Voltage: 14.4/24.9 kV Wye Grounded		74.168*		73.709*		72.315*
		(9.575)		(9.571)		(9.568)
Voltage: 2.4 kV Delta		125.026		124.055		114.017
		(129.035)		(128.970)		(128.890)
Voltage: 4.8 kV Delta		383.630*		383.628*		380.996*
		(91.024)		(90.979)		(90.702)
Voltage: 7.2 kV Delta		-64.652		-64.013		-51.593
		(64.420)		(64.388)		(64.349)
Voltage: 7.2/12.47 kV Wye Grounded		6.310		6.021		5.158
		(7.364)		(7.362)		(7.487)
Years Since Last Trim < 7		-29.600*		-26.703*		-26.028*
		(5.278)		(5.339)		(5.347)
Year: 2021			39.144*	40.393*		40.310*
			(7.038)	(7.028)		(7.030)
Year: 2022			-10.757	-7.720		-7.844
			(7.037)	(7.051)		(7.053)
Year: 2023			0.463	4.939		4.757
			(7.034)	(7.079)		(7.081)
Year: 2024			-12.060	-6.926		-7.124
			(7.026)	(7.081)		(7.084)
Primary Underground Percentage		-1.195*		-1.188*		-0.926*
		(0.170)		(0.170)		(0.192)
Customers per Primary Line Mile		-0.264*		-0.268*		-0.230*
		(0.089)		(0.089)		(0.094)
Open Wire Secondary Miles		-3.881*		-3.906*		-3.856*
		(1.440)		(1.440)		(1.512)
Mean Canopy Cover Percentage		3.737*		3.715*		3.710*
		(0.288)		(0.288)		(0.290)
Primary Miles		1.419*		1.419*		1.392*
		(0.143)		(0.143)		(0.148)

SAIDI including MEDs

For SAIDI including MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 3, while Table 15 reports the coefficient, p-value, and standard error for each independent variable in Models 1 through 6. As Figure 3 and Table 15 show, Voltage can have a large and statistically significant correlation with SAIDI including MEDs: when all other variables are held constant, 4.8 kV Delta and 14.4/24.9 kV Wye Grounded configurations have 1148 minute and 162 minute longer SAIDI including MEDs values, respectively, than the reference voltage (4.8/8.32 kV Wye Grounded), while 7.2/12.47 kV Wye Grounded feeders have a SAIDI excluding MEDs value that is 69 minutes shorter than that of the reference voltage. As previously discussed, feeder age may play a role in feeders with Delta configurations having longer average outage durations than the reference voltage.

With the exception of Years Since Last Trim < 7, all other feeder characteristics included in Model 6 have statistically significant correlations with SAIDI including MEDs and can be interpreted as follows, when all other variables are held constant:

- Primary Underground Percentage: A one percentage-point increase in Primary Underground Percentage is correlated with an 8 minute decrease in SAIDI excluding MEDs.
- Customers per Primary Line Mile: An increase of 1 customer per primary line mile is associated with a 1.3 minute decrease in SAIDI excluding MEDs.
- Open Wire Secondary Miles: Every one-mile increase in Open Wire Secondary Miles is associated with a 22.5 minute decrease in SAIDI excluding MEDs.
- Mean Canopy Cover Percentage: A one percentage-point increase in Mean Canopy Cover Percentage is associated with a 10 minute increase in SAIDI excluding MEDs.
- Primary Miles: Every one-mile increase in Primary Miles is associated with an approximately 5 minute increase in SAIDI excluding MEDs.

As previously discussed, the signs of these correlations between feeder characteristics largely accord with our physical understanding of the distribution system. Of the population characteristics included in Model 6, only Serves Urban has a statistically significant correlation with SAIDI excluding MEDs (as was the case with SAIDI including MEDs): a feeder serving an Urban census tract is associated with a 99 minute decrease in SAIDI excluding MEDs when all other variables are held constant, which may reflect how increased redundancy in the distribution system in more densely populated areas reduces average outage durations. Whether a feeder serves EJ, Low-Income, or High-Percent-Minority-Percentile census tracts is not statistically significant in Models 5 or 6 for SAIDI including MEDs.

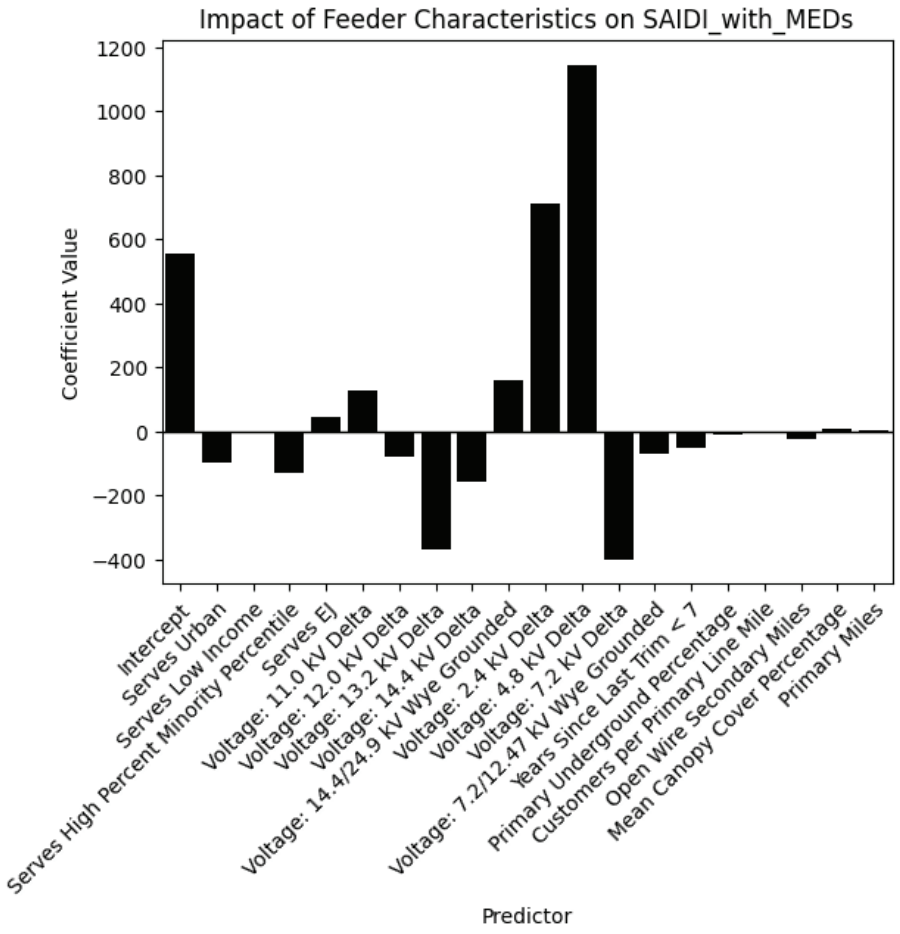


Figure 3. Regression coefficients for Model 6 (including feeder characteristics, population characteristics, and year fixed effects) of SAIDI including MEDs.

Table 15. Mixed-effects linear regression models for SAIDI including MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the $p < 0.05$ level.

Model:	1	2	3	4	5	6
Intercept	725.301*	705.064*	538.527*	518.580*	1011.405*	554.278*
	(16.238)	(45.396)	(28.379)	(50.814)	(20.830)	(52.291)
Serves Urban					-561.142*	-98.864*
					(31.724)	(41.092)
Serves Low Income					6.594	1.539
					(45.691)	(44.236)
Serves High Percent Minority Percentile					-142.664	-128.474
					(75.497)	(70.377)
Serves EJ					-16.676	45.602
					(54.581)	(53.532)
Voltage: 11.0 kV Delta		147.225		146.481		128.832
		(171.689)		(171.811)		(171.577)
Voltage: 12.0 kV Delta		-53.740		-46.929		-80.127
		(263.868)		(264.055)		(263.761)
Voltage: 13.2 kV Delta		-342.496		-336.525		-368.933
		(209.004)		(209.153)		(209.061)
Voltage: 14.4 kV Delta		-157.478		-153.411		-157.283
		(141.498)		(141.599)		(141.310)
Voltage: 14.4/24.9 kV Wye Grounded		166.915*		169.772*		162.460*
		(43.835)		(43.868)		(43.897)
Voltage: 2.4 kV Delta		731.503		736.116		712.088
		(590.447)		(590.866)		(590.936)
Voltage: 4.8 kV Delta		1161.665*		1161.593*		1145.654*
		(416.517)		(416.811)		(415.891)
Voltage: 7.2 kV Delta		-409.513		-413.884		-398.896
		(294.752)		(294.968)		(295.046)
Voltage: 7.2/12.47 kV Wye Grounded		-66.486*		-64.983		-67.947*
		(33.357)		(33.460)		(34.112)
Years Since Last Trim < 7		-29.526		-48.887		-49.726
		(26.412)		(26.413)		(26.462)
Year: 2021			414.386*	416.630*		416.672*
			(36.762)	(36.789)		(36.794)
Year: 2022			-67.408	-62.342		-62.099
			(36.758)	(36.894)		(36.900)
Year: 2023			537.361*	545.448*		545.742*
			(36.744)	(37.021)		(37.028)
Year: 2024			52.273	62.300		62.541
			(36.703)	(37.030)		(37.037)
Primary Underground Percentage		-8.805*		-8.872*		-8.010*
		(0.773)		(0.775)		(0.875)
Customers per Primary Line Mile		-1.601*		-1.572*		-1.316*
		(0.394)		(0.397)		(0.422)
Open Wire Secondary Miles		-28.844*		-28.937*		-22.519*
		(6.449)		(6.485)		(6.828)
Mean Canopy Cover Percentage		10.338*		10.507*		9.968*
		(1.316)		(1.318)		(1.330)
Primary Miles		5.470*		5.452*		4.929*
		(0.652)		(0.654)		(0.676)

SAIFI excluding MEDs

For SAIFI excluding MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 4, while Table 16 reports the coefficient, p-value, and standard error for each independent variable in Models 1 through 6.

As Figure 4 and Table 16 show, Voltage can have a large and statistically significant correlation with SAIFI excluding MEDs. Feeders with the 7.2/12.47 kV Wye Grounded configuration have an increase of 0.131 interruptions per customer per year in average SAIFI excluding MEDs compared to the reference voltage when all other variables are held constant, while feeders with the 14.4/24.9 kV Wye Grounded configuration have an increase of 0.342 interruptions per customer per year relative to the reference voltage. Feeders with a higher voltage in a Wye Grounded arrangement having more frequent outages reflects that the same outage mechanism – such as contact from vegetation – is more likely to cause an outage on higher-voltage feeders because of the increase in fault current compared to the fault current that would occur at the reference voltage (4.8/8.32 kV Wye Grounded). Among feeders with a Delta configuration, those with a 4.8 kV Delta configuration have an increase of 1.1 interruptions per customer per year in average SAIFI excluding MEDs relative to the reference voltage; those with an 11.0 kV Delta configuration have an increase of 0.4 interruptions per customer per year relative to the reference voltage; and those with a 14.4 kV Delta configuration have an increase of 0.608 interruptions per customer per year relative to the reference voltage when all other variables are held constant. Feeders with Delta configurations having more frequent outages than those at the reference voltage may reflect that those feeders tend to be older than those at the reference voltage.

With the exception of Customers per Primary Line Mile, all other feeder characteristics included in Model 6 have statistically significant correlations with SAIFI excluding MEDs and can be interpreted as follows, when all other variables are held constant:

- Years Since Last Trim < 7: Vegetation in proximity to a feeder having been trimmed in the last 7 years is correlated with a decrease of 0.072 interruptions per customer per year in SAIFI excluding MEDs.
- Primary Underground Percentage: A one percentage-point increase in Primary Underground Percentage is correlated with a decrease of 0.004 interruptions per customer per year in SAIFI excluding MEDs.
- Open Wire Secondary Miles: Every one-mile increase in Open Wire Secondary Miles is associated with a decrease of 0.013 interruptions per customer per year in SAIFI excluding MEDs.
- Mean Canopy Cover Percentage: A one percentage-point increase in Mean Canopy Cover Percentage is associated with an increase of 0.016 interruptions per customer per year in SAIFI excluding MEDs.
- Primary Miles: Every one-mile increase in Primary Miles is associated with an increase of 0.007 interruptions per customer per year in SAIFI excluding MEDs.

The signs of these correlations between feeder characteristics largely accord with our physical understanding of the distribution system. For example, as the amount of nearby vegetation increases, interruptions tend to occur more frequently. Similarly, as the length of a feeder

increases, the frequency of interruptions increases, which reflects the increased exposure to different hazards and failure modes that comes with greater feeder length.

Of the population characteristics included in Model 6, only Serves EJ has a statistically significant correlation with SAIFI excluding MEDs: a feeder serving an EJ census tract is associated with an increase of approximately 0.1 interruptions per customer per year in SAIFI excluding MEDs compared to feeders not serving EJ census tracts when all other variables are held constant. This result is of practical significance given that the average SAIFI excluding MEDs across feeders in Consumers' distribution system is approximately 1.0 interruptions per customer per year (Table 4) and indicates that there is some difference in feeders serving EJ and Non-EJ census tracts even when the many other circuit and demographic characteristics included in Model 6 are controlled for. It is not clear what physical characteristic of circuits serving EJ census tracts may be driving this observation of poorer reliability, since controls are included for all available feeder characteristic data in Model 6. One likely influential feeder characteristic not included as an independent variable in the models is feeder age: older feeders would likely be prone to more frequent interruptions. Whether a feeder serves Urban, Low-Income, or High-Percent-Minority-Percentile census tracts is not statistically significant in Model 6 for SAIFI excluding MEDs.

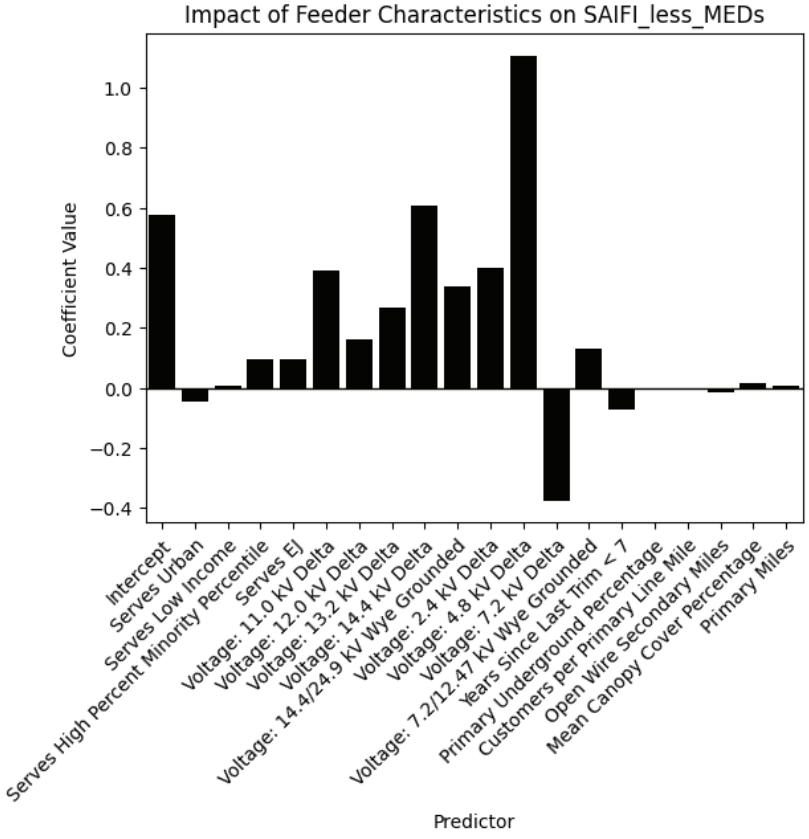


Figure 4. Regression coefficients for Model 6 (including feeder characteristics, population characteristics, and year fixed effects) of SAIFI excluding MEDs.

Table 16. Mixed-effects linear regression models for SAIFI excluding MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the $p < 0.05$ level.

Model:	1	2	3	4	5	6
Intercept	1.001*	0.572*	1.016*	0.578*	1.234*	0.574*
	(0.015)	(0.041)	(0.024)	(0.045)	(0.020)	(0.046)
Serves Urban					-0.466*	-0.047
					(0.031)	(0.037)
Serves Low Income					-0.045	0.007
					(0.045)	(0.041)
Serves High Percent Minority Percentile					0.046	0.097
					(0.076)	(0.066)
Serves EJ					0.035	0.096*
					(0.045)	(0.044)
Voltage: 11.0 kV Delta		0.392*		0.393*		0.389*
		(0.155)		(0.155)		(0.155)
Voltage: 12.0 kV Delta		0.168		0.165		0.160
		(0.239)		(0.239)		(0.238)
Voltage: 13.2 kV Delta		0.280		0.278		0.267
		(0.189)		(0.189)		(0.189)
Voltage: 14.4 kV Delta		0.616*		0.615*		0.609*
		(0.128)		(0.128)		(0.128)
Voltage: 14.4/24.9 kV Wye Grounded		0.344*		0.343*		0.339*
		(0.040)		(0.040)		(0.040)
Voltage: 2.4 kV Delta		0.423		0.421		0.399
		(0.534)		(0.534)		(0.534)
Voltage: 4.8 kV Delta		1.114*		1.114*		1.107*
		(0.377)		(0.377)		(0.376)
Voltage: 7.2 kV Delta		-0.416		-0.415		-0.375
		(0.267)		(0.267)		(0.266)
Voltage: 7.2/12.47 kV Wye Grounded		0.136*		0.136*		0.131*
		(0.031)		(0.031)		(0.031)
Years Since Last Trim < 7		-0.080*		-0.074*		-0.072*
		(0.022)		(0.022)		(0.022)
Year: 2021			0.050	0.053		0.053
			(0.029)	(0.029)		(0.029)
Year: 2022			-0.086*	-0.078*		-0.078*
			(0.029)	(0.029)		(0.029)
Year: 2023			-0.013	-0.000		-0.001
			(0.029)	(0.029)		(0.029)
Year: 2024			-0.026	-0.011		-0.012
			(0.029)	(0.029)		(0.029)
Primary Underground Percentage		-0.005*		-0.005*		-0.004*
		(0.001)		(0.001)		(0.001)
Customers per Primary Line Mile		-0.000		-0.000		-0.000
		(0.000)		(0.000)		(0.000)
Open Wire Secondary Miles		-0.012*		-0.012*		-0.013*
		(0.006)		(0.006)		(0.006)
Mean Canopy Cover Percentage		0.016*		0.016*		0.016*
		(0.001)		(0.001)		(0.001)
Primary Miles		0.007*		0.007*		0.007*
		(0.001)		(0.001)		(0.001)

SAIFI including MEDs

For SAIFI including MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 5, while Table 17 reports the coefficient, p-value, and standard error for each independent variable in Models 1 through 6. In Model 6, which includes both feeder and demographic characteristics, the same independent variables that had statistically significant correlations with SAIFI excluding MEDs also have statistically significant correlations with SAIFI including MEDs; the signs of statistically significant regression coefficients for SAIFI including MEDs are largely similar, albeit typically somewhat larger, than those for SAIFI excluding MEDs. This suggests that the inclusion of MEDs does not fundamentally change the relationships between feeder and population characteristics and the frequency of outages. As was the case for Model 6 for SAIFI excluding MEDs, only Serves EJ has a statistically significant correlation with SAIFI including MEDs of the four population characteristics considered: a feeder serving an EJ census tract is associated with an increase of approximately 0.128 interruptions per customer per year in SAIFI including MEDs compared to feeders not serving EJ census tracts when all other variables are held constant. This result is of practical significance given that the average SAIFI including MEDs across all feeders in Consumers' distribution system has ranged from approximately 1.2 to 1.6 interruptions per customer per year from 2020 through 2024 (Table 4). As previously discussed, this result indicates that there is some difference in feeders serving EJ and Non-EJ census tracts even when the many other circuit and demographic characteristics included in Model 6 are controlled for. Feeder age, which was not included as an independent variable, may play a role in this observation, since older feeders would likely be prone to more frequent interruptions.

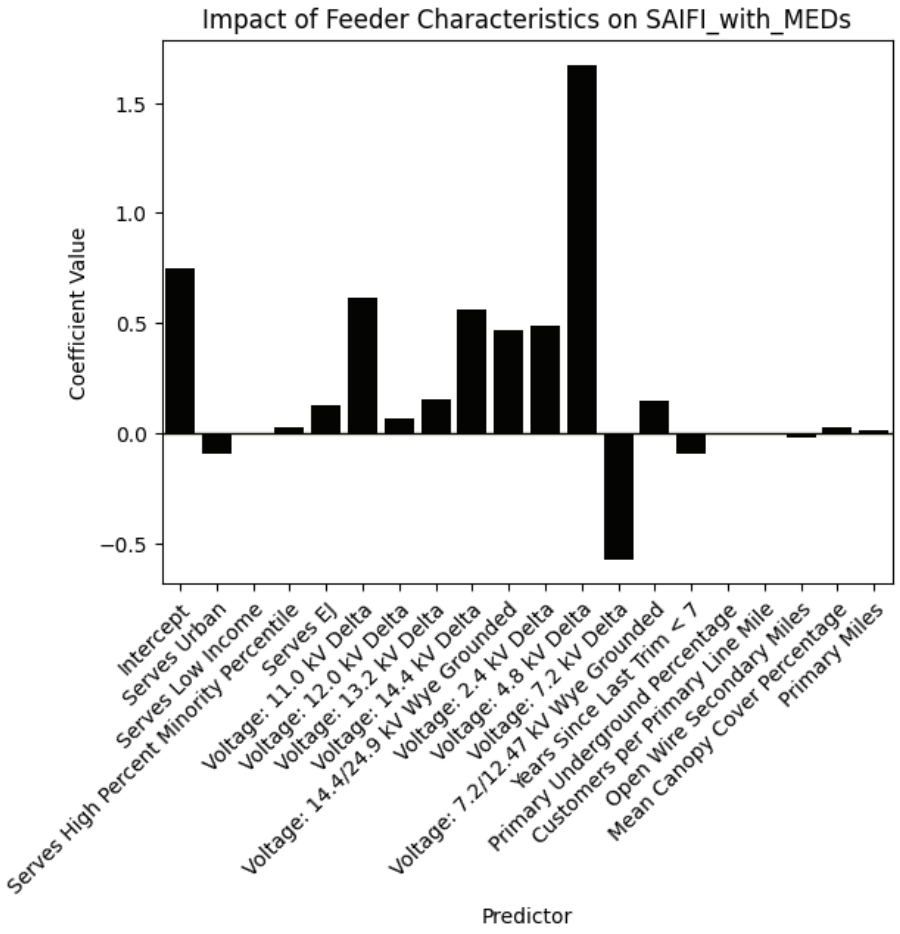


Figure 5. Regression coefficients for Model 6 (including feeder characteristics, population characteristics, and year fixed effects) of SAIFI including MEDs.

Table 17. Mixed-effects linear regression models for SAIFI including MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the $p < 0.05$ level.

Model:	1	2	3	4	5	6
Intercept	1.429*	0.827*	1.340*	0.730*	1.808*	0.745*
	(0.021)	(0.054)	(0.032)	(0.059)	(0.027)	(0.061)
Serves Urban					-0.748*	-0.092
					(0.042)	(0.049)
Serves Low Income					-0.069	-0.011
					(0.061)	(0.054)
Serves High Percent Minority Percentile					-0.046	0.026
					(0.104)	(0.087)
Serves EJ					0.040	0.128*
					(0.059)	(0.057)
Voltage: 11.0 kV Delta		0.623*		0.623*		0.612*
		(0.205)		(0.205)		(0.204)
Voltage: 12.0 kV Delta		0.083		0.086		0.063
		(0.314)		(0.314)		(0.314)
Voltage: 13.2 kV Delta		0.181		0.183		0.155
		(0.249)		(0.249)		(0.249)
Voltage: 14.4 kV Delta		0.565*		0.566*		0.559*
		(0.169)		(0.169)		(0.168)
Voltage: 14.4/24.9 kV Wye Grounded		0.472*		0.473*		0.466*
		(0.052)		(0.052)		(0.052)
Voltage: 2.4 kV Delta		0.502		0.504		0.487
		(0.704)		(0.704)		(0.703)
Voltage: 4.8 kV Delta		1.690*		1.689*		1.673*
		(0.496)		(0.496)		(0.495)
Voltage: 7.2 kV Delta		-0.612		-0.614		-0.574
		(0.351)		(0.351)		(0.351)
Voltage: 7.2/12.47 kV Wye Grounded		0.157*		0.158*		0.148*
		(0.040)		(0.040)		(0.041)
Years Since Last Trim < 7		-0.088*		-0.096*		-0.094*
		(0.028)		(0.029)		(0.029)
Year: 2021			0.266*	0.271*		0.271*
			(0.037)	(0.037)		(0.037)
Year: 2022			-0.102*	-0.092*		-0.092*
			(0.037)	(0.037)		(0.037)
Year: 2023			0.131*	0.147*		0.146*
			(0.037)	(0.037)		(0.037)
Year: 2024			0.152*	0.170*		0.170*
			(0.037)	(0.037)		(0.037)
Primary Underground Percentage		-0.009*		-0.009*		-0.008*
		(0.001)		(0.001)		(0.001)
Customers per Primary Line Mile		-0.001		-0.001		-0.001
		(0.000)		(0.000)		(0.001)
Open Wire Secondary Miles		-0.022*		-0.022*		-0.019*
		(0.008)		(0.008)		(0.008)
Mean Canopy Cover Percentage		0.024*		0.024*		0.024*
		(0.002)		(0.002)		(0.002)
Primary Miles		0.011*		0.011*		0.011*
		(0.001)		(0.001)		(0.001)

Summary of Feeder-Level Reliability Regression Analysis Results

As expected, many physical characteristics of feeders – such as Voltage – and their surroundings – such as Mean Canopy Cover – impact the average frequency and duration of their outages, as measured by SAIDI and SAIFI. Of the physical characteristics included in the regression models, Voltage often has a statistically significant and relatively large effect on SAIDI and SAIFI, both including and excluding MEDs, indicating that feeder voltages and configurations other than the reference voltage often have quite different average reliability than the reference voltage (4.8/8.32 kV Wye Grounded, the most common circuit configuration in the distribution system). Since different voltages and configurations – in particular, Delta circuits – often represent municipal utilities acquired over time by Consumers, feeder age may play a part in the varying average reliability of circuits not at the reference voltage. Feeder age was not available for the present study, and further work would be required to understand its impact on feeder reliability.

Primary Miles and Mean Canopy Cover Percentage had statistically significant, positive correlations with SAIDI and SAIFI, both excluding and including MEDs, in the combined effects regression models of reliability (Model 6). These correlations indicate that as Primary Miles and Mean Canopy Cover Percentage increases, feeder reliability tends to worsen. As the length of primary miles on a circuit increases, so does its exposure to different hazards – such as vegetation – that could cause interruptions. More primary line miles also require more associated equipment, which has its own failure modes that could lead to interruptions. Similarly, as the amount of vegetation proximal to a feeder increases, so too does the likelihood of it coming into contact with a conductor and causing an outage. This also explains why Primary Underground Percentage had statistically significant, negative correlations with both SAIDI and SAIFI, indicating that as the proportion of a feeder that is underground increases, reliability tends to improve. For similar reasons, Years Since Last Trim < 7 had statistically significant, negative correlations with all but one of the four reliability metrics studied in this regression analysis, indicating that more than 7 years having elapsed since vegetation near a circuit was last trimmed back is associated with worse average reliability.

Four characteristics of the communities served by feeders were included in regression models of SAIDI and SAIFI: whether a feeder serves Urban, EJ, Low-Income, or High-Percent-Minority-Percentile census tracts, respectively. Feeders serving Urban census tracts tend to have shorter outages than those that do not serve Urban census tracts, even when other feeder and population characteristics are controlled for. Whether a feeder serves EJ, Low-Income, or High-Percent-Minority-Percentile census tracts was not found to have a statistically significant correlation with outage duration in terms of SAIDI including MEDs or SAIDI excluding MEDs.

Whether a feeder serves EJ census tracts was found to have a statistically significant correlation with the frequency of outages in terms of SAIFI excluding MEDs and SAIFI including MEDs: feeders that serve EJ census tracts tend to have more frequent outages than those that serve only Non-EJ census tracts, even when controlling for other feeder characteristics (Voltage, Years Since Last Trim < 7, Primary Underground Percentage, Customers per Primary Line Mile, Open-Wire Secondary Miles, Mean Canopy Cover Percentage, and Primary Miles) and characteristics of the communities served by a feeder (Urban, Low Income, and High Percent Minority Percentile). This indicates that differences in outage frequency on feeders serving EJ and non-EJ census tracts are not explained by the other feeder and population characteristics included in

Model 6 for SAIFI excluding MEDs and SAIFI including MEDs. Whether a feeder serves Urban, Low-Income, or High-Minority-Percentile census tracts was not found to have statistically significant correlations with SAIFI.

Regression Analysis Results: Residential Disconnection Rates

We developed different types of linear regression models relating rates of residential disconnections in Consumers' service territory from 2020 through 2023 at the 2020 Census-tract level to demographic characteristics from the American Community Survey (ACS), using 5-Year Estimates, which represent the average conditions in a census tract over a five-year period.[30] At the time of this analysis, ACS 5-year estimates for 2024 were unavailable; therefore, disconnections that occurred in 2024 were excluded. Table 1 details the ACS variables used in the analysis and provides the associated codes and a brief description of the ACS census tract table data. Additional variables included in this analysis, and how they were calculated, are detailed in Table 2.

We used the following independent variables in the disconnection regression models:

- Median Home Value (in $10,000 increments);
- Percentage Minority Population;
- Percentage Below Poverty;
- Unemployment Rate;
- Percentage Renters;
- Percentage of Homes Built after 1990; and
- Population Density in units of households per square mile (in 1000 household increments).

The dependent variable in the regression is the disconnection rate, which was calculated the number of disconnections per 1000 households.

Descriptive Analysis of Residential Disconnection Rates

Table 18 shows yearly statistics (mean, standard deviation, minimum, and maximum values) for disconnection rates across all census tracts in Consumers' service territory from 2020 through 2023. Figure 6 Figure 6 plots the average disconnection rate in each year and shows that the disconnection rate in 2020 is substantially lower (fewer than 15 disconnections per 1000 households) than in 2021 through 2023, when the average annual disconnection rate among all census tracts in Consumers' service territory was approximately 50 disconnections per 1000 households. The smaller average disconnection rate in 2020 results from a moratorium on disconnections instituted by Consumers in response to the COVID-19 pandemic. Figure 7 through Figure 10 show the distribution of disconnection rates for each year. The distributions of disconnection rates are right-skewed, with many census tracts experiencing disconnection rates below 50 disconnections per 1000 households, roughly the mean disconnection rate among all census tracts in 2021 through 2023. Figure 11 maps the average disconnection rate from 2020 through 2023 for each census tract. A comparison of Figure 11 and Figure 12, which maps the

[30] https://www.census.gov/programs-surveys/acs/guidance/estimates.html

average population density of each census tract over the same time period, shows that the areas with higher population density tend to also be areas with higher disconnection rates, while areas with lower population density tend to also be areas with lower disconnection rates.

Table 18. The mean, standard deviation, minimum, and maximum disconnection rates (in units of disconnections per 1000 households) among census tracts in Consumers' service territory from 2020 through 2023.

Year	Mean	Standard Deviation	Minimum	Maximum
2020	14.85	11.54	0.40	80.62
2021	51.01	46.41	0.43	327.27
2022	49.33	44.90	0.37	279.87
2023	56.51	50.34	0.43	417.54

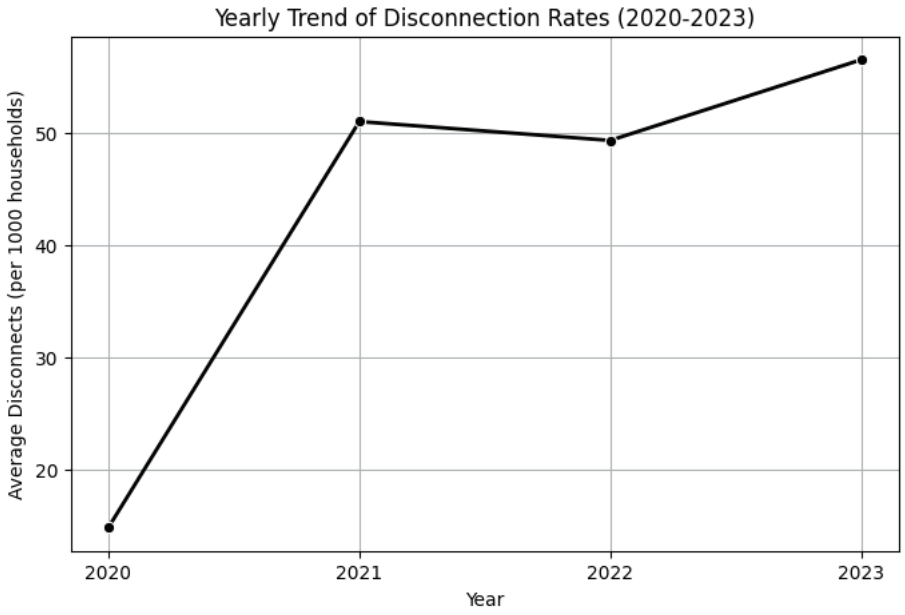


Figure 6. Average annual disconnection rate (disconnections per 1000 households) for each year from 2020 through 2023 among 2020 census tracts in Consumers' service territory.

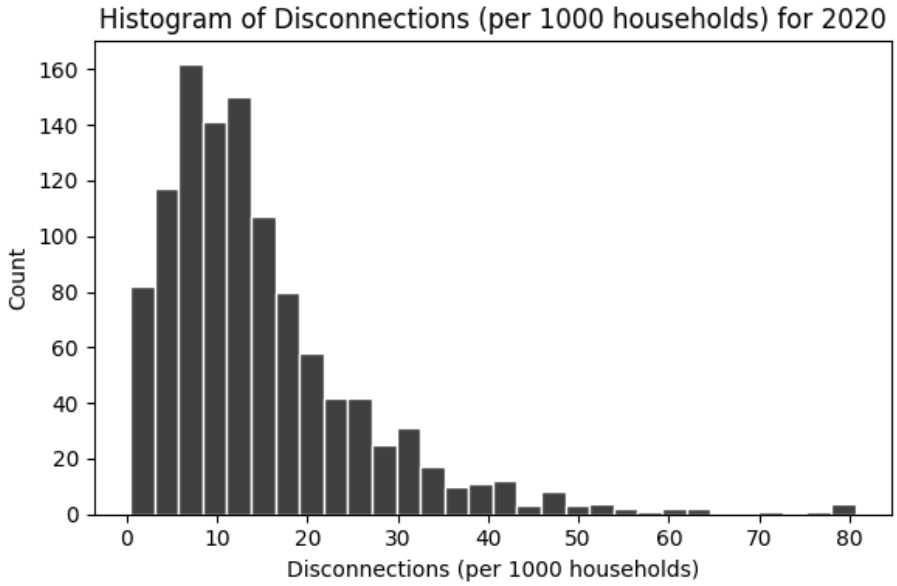


Figure 7. Histogram of 2020-census-tract-level disconnection rates (disconnections per 1000 households) for 2020.

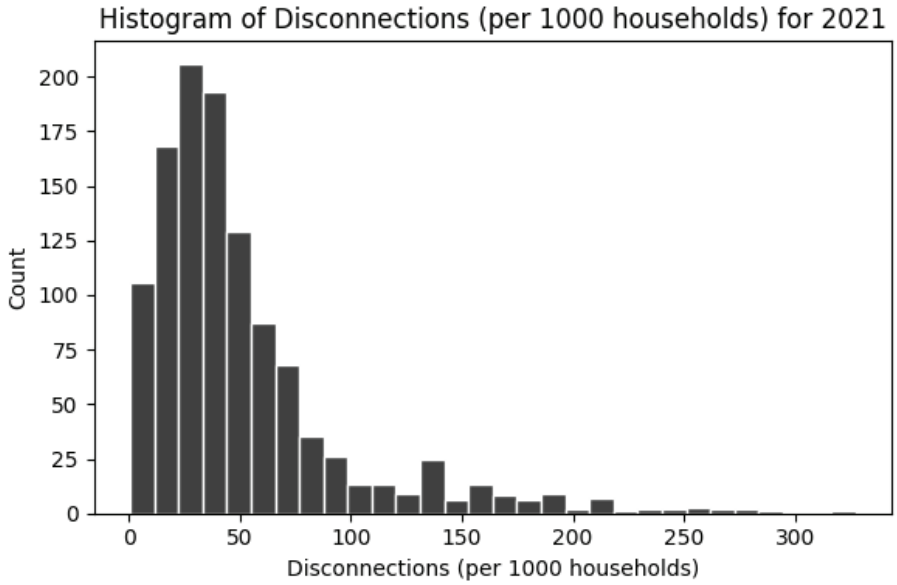


Figure 8. Histogram of 2020-census-tract-level disconnection rates (disconnections per 1000 households) for 2021.

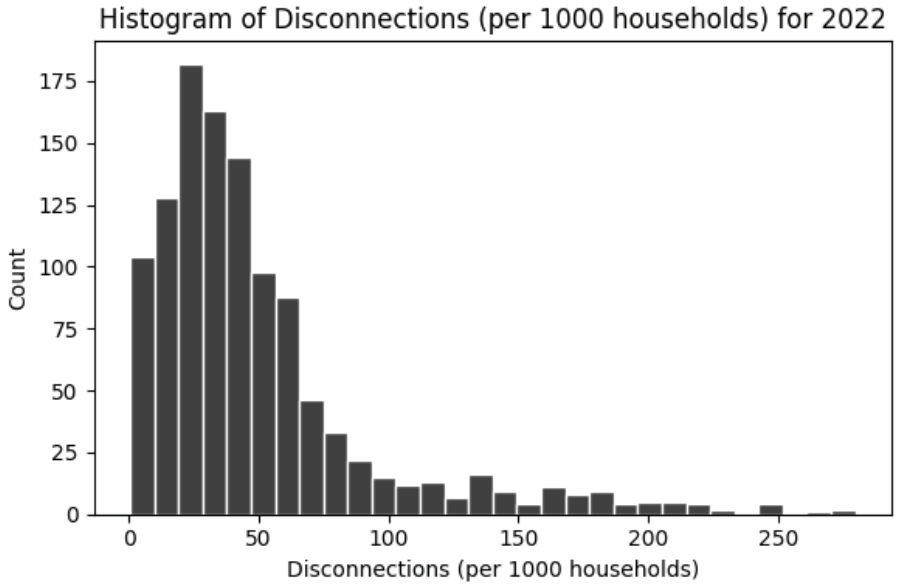


Figure 9. Histogram of 2020-census-tract-level disconnection rates (disconnections per 1000 households) for 2022.

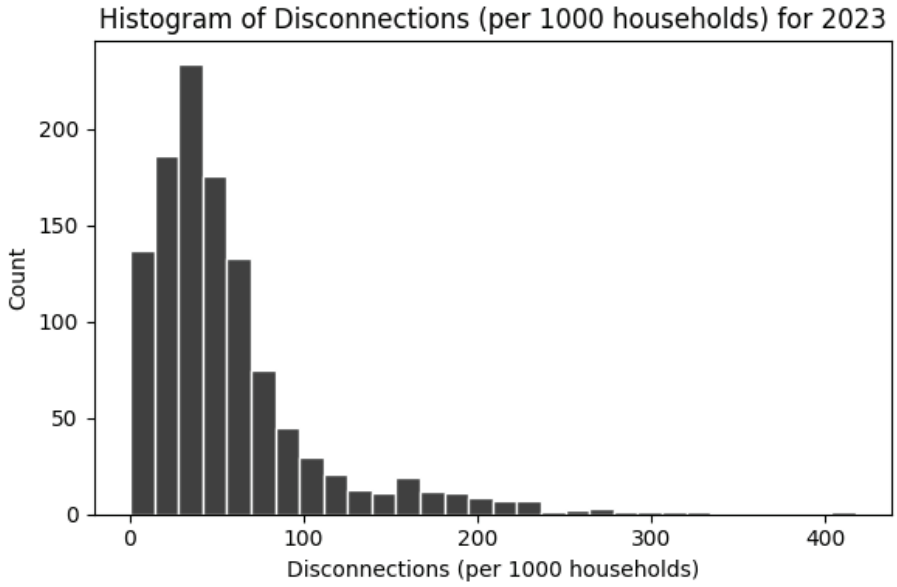


Figure 10. Histogram of 2020-census-tract-level disconnection rates (disconnections per 1000 households) for 2023.

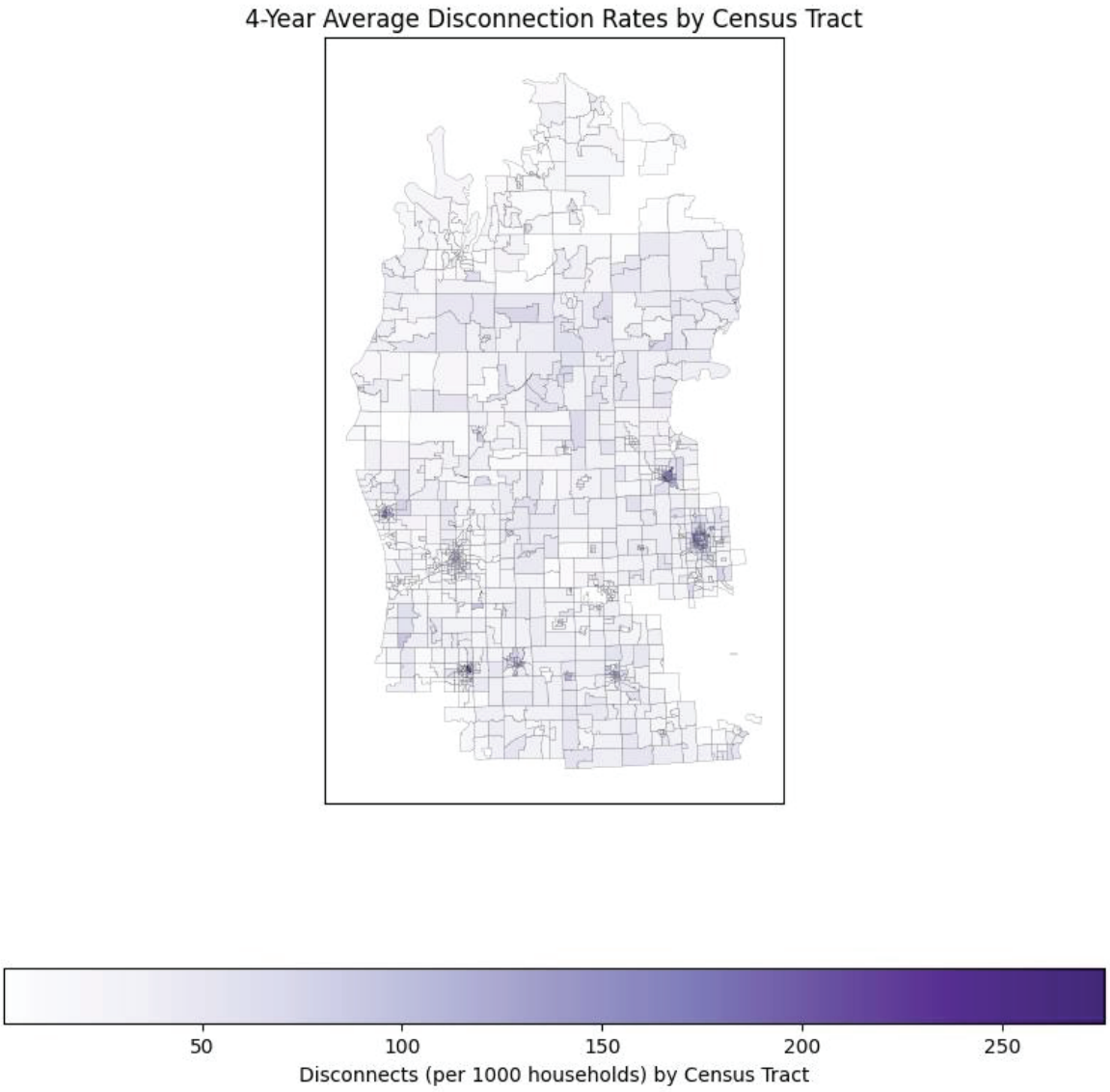


Figure 11. Map of average disconnection rate from 2020 through 2023, in units of disconnections per 1000 households, by census tract in Consumers' service territory.

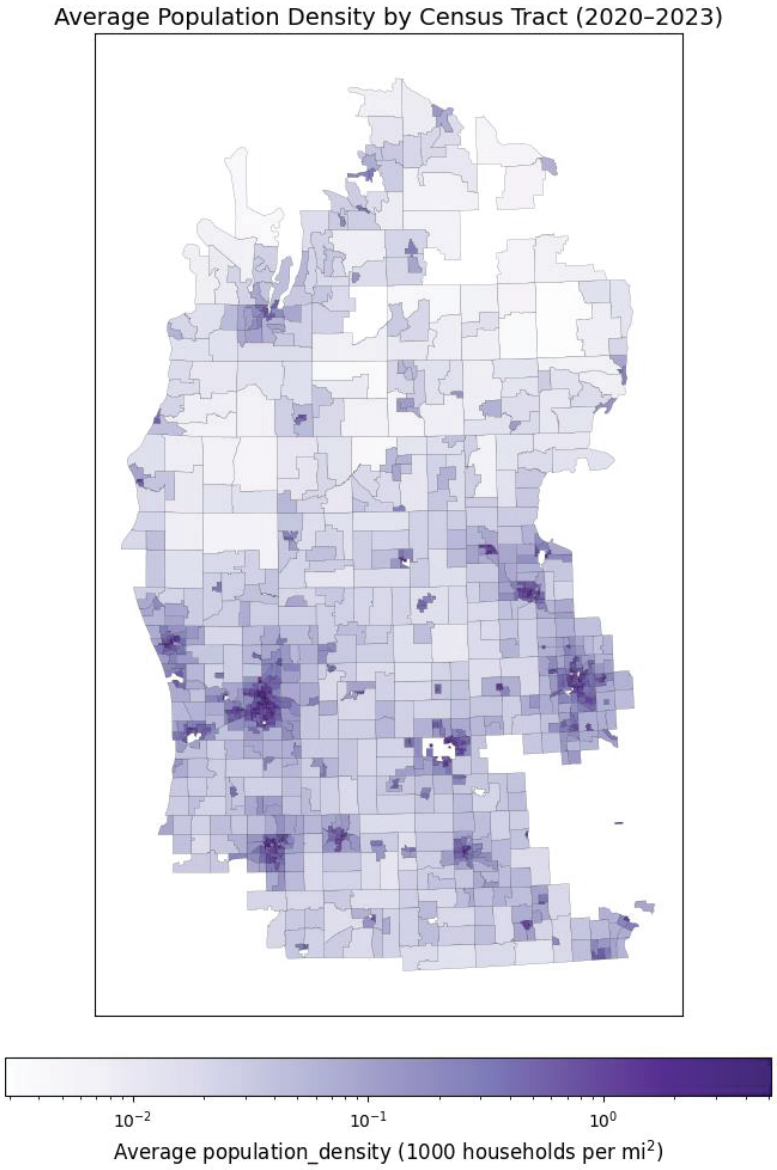


Figure 12. Map of average population density from 2020 through 2023 in units of 1000 households per square mile for each census tract in Consumers' service territory.

Comparing the Average Disconnection Rates of Groups of Census Tracts

To assess whether there were statistically significant differences in the average disconnection rates of groups of census tracts in the Consumers service territory from 2020 through 2024, we carried out the binary difference-in-means *t*-test previously described for each of the following paired groups of census tracts in each year:

- Low Income and High Income; and
- High Percentage Minority Population and Low Percentage Minority Population.

The following subsections detail the findings of each set of comparisons.

Low-Income and High-Income Census Tracts

For Low-Income and High-Income census tracts, the results of the binary difference-in-means t-test for each year from 2020 through 2024 are shown in Table 19. Statistically significant differences in the mean disconnection rate of Low-Income and High-Income census tracts are observed in each year, and Low-Income census tracts consistently experience higher (worse) disconnection rates on average.

Table 19. Comparison of 2020 census-tract-level disconnection rates for each year from 2020 through 2024 averaged for Low-Income and High-Income census tracts. The difference is calculated by subtracting the Low-Income Mean from the High-Income Mean. Statistical significance is assessed at $\alpha = 0.05$, and the group that experiences a worse average disconnection rate is assessed only for statistically significant differences in mean disconnection rate.

Year	High-Income Mean	Low-Income Mean	Difference	p-value	Significant?	Worse?
2020	7.37	15.69	-8.31	2.70E-35	TRUE	Low-Income
2021	20.65	54.44	-33.78	1.41E-57	TRUE	Low-Income
2022	18.98	52.74	-33.76	6.29E-65	TRUE	Low-Income
2023	23.70	60.21	-36.51	1.28E-55	TRUE	Low-Income
2024	26.94	69.67	-42.73	7.15E-65	TRUE	Low-Income

High-Percentage-Minority-Population and Low-Percentage-Minority-Population Census Tracts

For High-Percentage-Minority-Population and Low-Percentage-Minority-Population census tracts, the results of the binary difference-in-means t-test for each year from 2020 through 2024 are shown in Table 20. Statistically significant differences in the mean disconnection rate experienced by High-Percentage-Minority-Population and Low-Percentage-Minority-Population census tracts are observed in each year, and High-Percentage-Minority-Population census tracts consistently experience higher (worse) disconnection rates on average.

Table 20. Comparison of 2020 census-tract-level disconnection rates for each year from 2020 through 2024 averaged for Low-Percentage-Minority-Population and High-Percentage-Minority-Population census tracts. The difference is calculated by subtracting the High-Percentage-Minority-Population Mean from the Low-Percentage-Minority-Population. Statistical significance is assessed at $\alpha = 0.05$, and the group that experiences a worse average disconnection rate is assessed only for statistically significant differences in mean disconnection rate.

Year	Low-Minority Mean	High-Minority Mean	Difference	p-value	Significant?	Worse?
2020	12.75	33.90	-21.16	6.52E-25	TRUE	High-Minority
2021	41.48	138.72	-97.24	3.63E-27	TRUE	High-Minority
2022	40.40	132.83	-92.43	3.58E-29	TRUE	High-Minority
2023	46.38	154.11	-107.73	4.02E-31	TRUE	High-Minority
2024	53.85	175.47	-121.62	2.49E-37	TRUE	High-Minority

Simple Linear Regression Results

To assess how much of the variability in disconnection rate could be explained by individual independent variables alone, we regressed the disconnection rate on each independent variable separately. For each independent variable, we fit simple linear regression models (Figure 20 through Figure 26) using a partial set of disconnection data (2021-2023)[31] as well as to each year of disconnection data (2020-2023); the R^2 values and regression coefficients of each model are reported in Table 21. In simple linear regression models fit using all disconnection data from 2021 through 2023, Percentage Minority Population, Percentage Below Poverty, Unemployment Rate, and Percentage Renters are all positively correlated with disconnection rate. Each percentage point increase in these variables is associated with more disconnections per 1000 households. In contrast, Median Home Value and Percentage of Homes Built after 1990 are negatively correlated with disconnection rate, suggesting that census tracts with newer or more expensive homes tend to experience lower disconnection rates than census tracts with older or less expensive homes. Each independent variable has the following effect on disconnection rate:

- Median Home Value: A $10,000 increase in a census tract's Median Home Value is associated with a decrease of approximately 3.1 disconnections per 1000 households.
- Percentage Minority Population: A one percentage-point increase in minority population is associated with an increase of approximately 1.7 disconnections per 1000 households.
- Percentage Below Poverty Population: A one percentage-point increase in below poverty population is associated with an increase of approximately 2.8 disconnections per 1000 households.
- Unemployment Rate: A one percentage-point increase in unemployment rate is associated with an increase of 5.0 disconnections per 1000 households.
- Percentage Renters: A one percentage-point increase in the percentage of renters is associated with an increase of approximately 1.3 disconnections per 1000 households.
- Percentage of Homes Built after 1990: A one percentage-point increase in the percentage of homes built after 1990 is associated with a decrease of approximately 1.2 disconnections per 1000 households.

[31] Disconnection data for 2020 was excluded given the moratorium in place for most of that year.

- Population Density: An increase of 1000 households per square mile is associated with an increase of 23.1 disconnections per 1000 households.

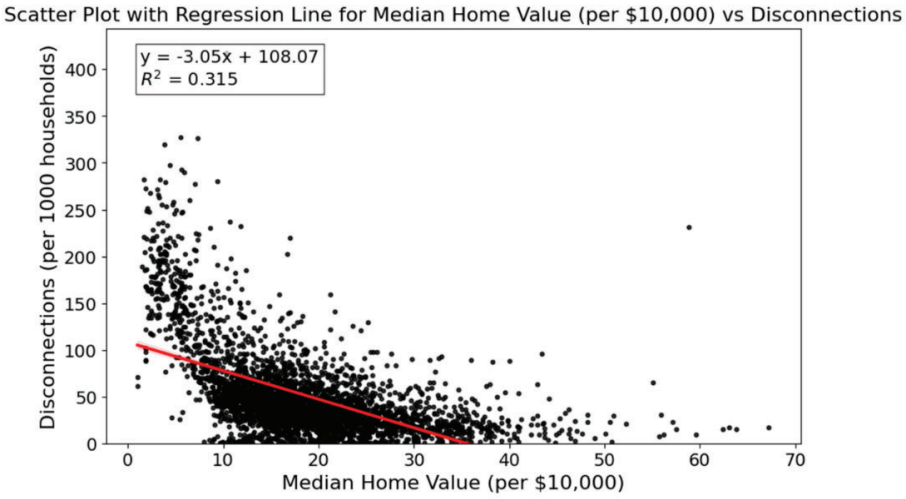


Figure 13. Scatter plot of disconnection rate (disconnections per 1000 households) versus Median Home Value (per $10,000) with best-fit line and R^2 value for a simple linear regression.

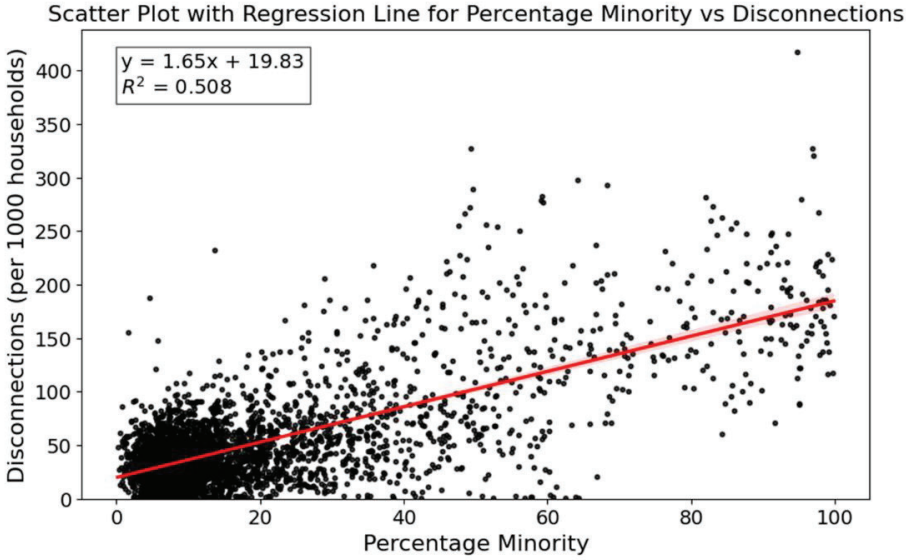


Figure 14. Scatter plot of disconnection rate (disconnections per 1000 households) versus Percentage Minority with best-fit line and R^2 value for a simple linear regression.

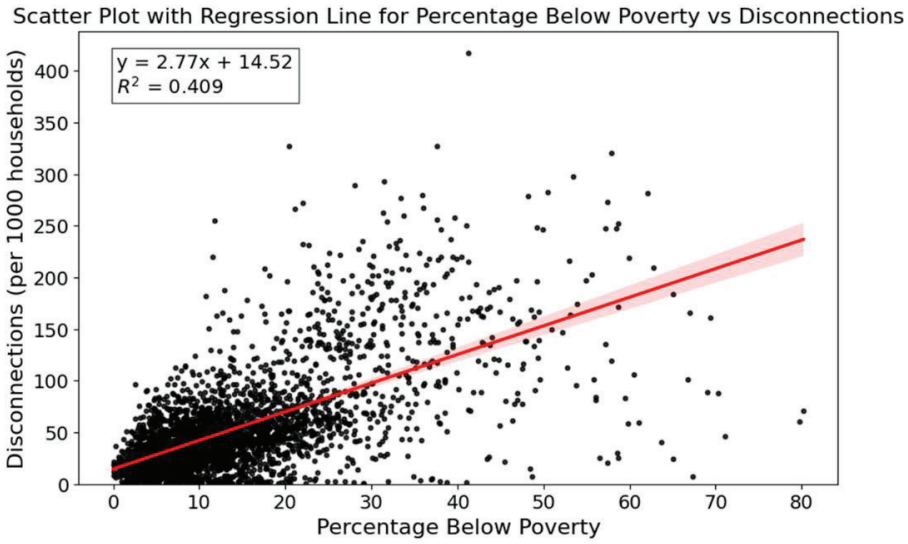


Figure 15. Scatter plot of disconnection rate (disconnections per 1000 households) versus Percentage Below Poverty with best-fit line and R^2 value for a simple linear regression.

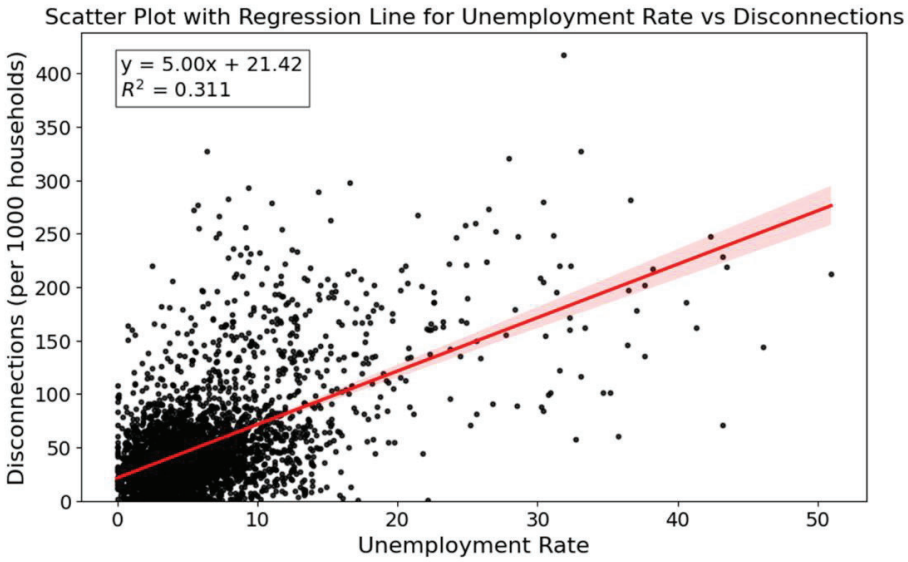


Figure 16. Scatter plot of disconnection rate (disconnections per 1000 households) versus Unemployment Rate with best-fit line and R^2 value for a simple linear regression.

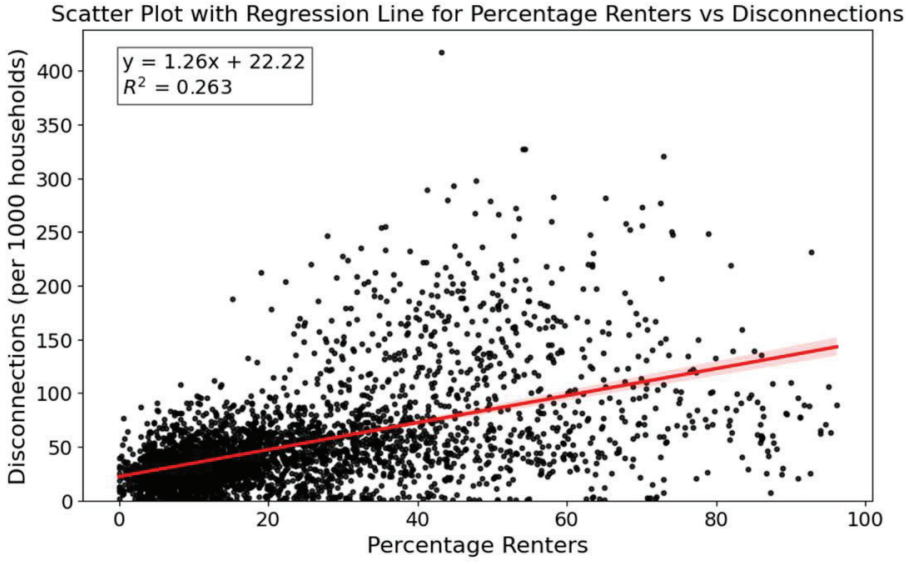


Figure 17. Scatter plot of disconnection rate (disconnections per 1000 households) versus Percentage Renters with best-fit line and R^2 value for a simple linear regression.

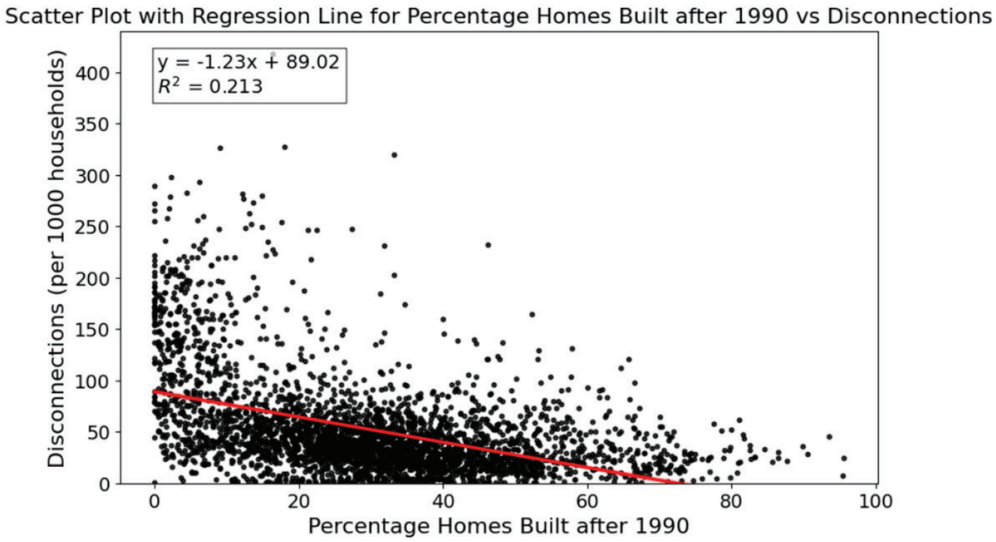


Figure 18. Scatter plot of disconnection rate (disconnections per 1000 households) versus Percentage of Homes Built After 1990 with best-fit line and R^2 value for a simple linear regression.



Figure 19. Scatter plot of disconnection rate (disconnections per 1000 households) versus Population Density (1000 households per square mile) with best-fit line and R^2 value for a simple linear regression.

Table 21 shows the results of fitting simple linear regression models to each independent variable in each year from 2020 through 2023: namely, the regression coefficients and their p-values. When individually regressed against disconnection rate, each independent variable coefficient is significant for every year. Notably, the estimated effect of the independent variables is reduced for 2020 relative to 2021 through 2023, where the estimates are more similar in magnitude. For each year, Median Home Value, Percentage Minority, and Percentage Below Poverty have the highest R^2 values, indicating these variables tend to better explain the variability in disconnection rates in these simple regression models than the other variables considered.

Figure 20 through Figure 26 show how the coefficient estimates change over time to reveal temporal trends for each independent variable. For example, Figure 21 shows that the coefficient for Percentage Minority Population increases each year from 2020 through 2023; in other words, the increase in the disconnection rate associated with a 1 percentage point increase in Percentage Minority Population was greater in 2023 than it was in each preceding year. For all predictor variables, the magnitude of the effect is consistently lower in the year 2020 compared to subsequent years, as would be expected given the moratorium on disconnections implemented by Consumers for the better part of that year. For all variables, there appears to be a slight reduction in effect magnitude in 2022, followed by an increase in effect in 2023. The study investigates time-based fixed effects in the Panel Linear Regression Results section.

Table 21. R^2, coefficient, and p-values for simple regression models fit by year from 2020 through 2023. * indicates significance at the $p < 0.05$ level.

Year	Variable	R^2	Coefficient	Standard Error
2020	Median Home Value (per $10,000)	0.347	-0.973*	0.040
	Percentage Minority	0.392	0.349*	0.013
	Percentage Below Poverty	0.356	0.615*	0.025
	Unemployment Rate	0.227	1.080*	0.060
	Percentage Renters	0.246	0.299*	0.016
	Percentage Homes Built after 1990	0.199	-0.295*	0.018
	Population Density	0.125	5.735*	0.454
2021	Median Home Value (per $10,000)	0.354	-3.719*	0.149
	Percentage Minority	0.498	1.581*	0.047
	Percentage Below Poverty	0.436	2.766*	0.093
	Unemployment Rate	0.325	4.962*	0.212
	Percentage Renters	0.275	1.264*	0.061
	Percentage Homes Built after 1990	0.217	-1.236*	0.069
	Population Density	0.119	22.769*	1.836
2022	Median Home Value (per $10,000)	0.338	-2.981*	0.124
	Percentage Minority	0.512	1.569*	0.045
	Percentage Below Poverty	0.406	2.634*	0.094
	Unemployment Rate	0.320	4.674*	0.202
	Percentage Renters	0.269	1.204*	0.059
	Percentage Homes Built after 1990	0.217	-1.178*	0.066
	Population Density	0.122	22.175*	1.764
2023	Median Home Value (per $10,000)	0.334	-3.111*	0.130
	Percentage Minority	0.522	1.805*	0.051
	Percentage Below Poverty	0.395	2.910*	0.107
	Unemployment Rate	0.309	5.513*	0.245
	Percentage Renters	0.255	1.305*	0.066
	Percentage Homes Built after 1990	0.213	-1.288*	0.073
	Population Density	0.123	24.210*	1.917

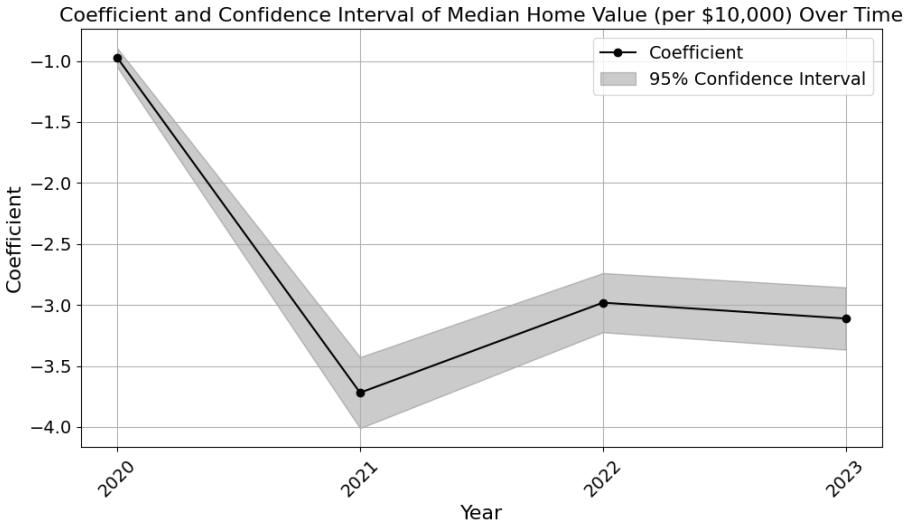


Figure 20. Coefficients for Median Home Value (per $10,000) in simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.

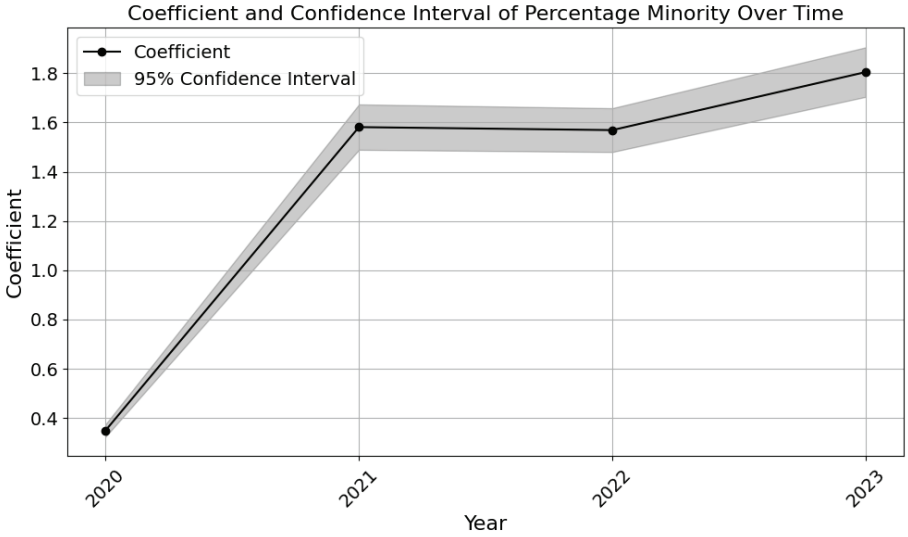


Figure 21. Coefficients for Percentage Minority in simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.

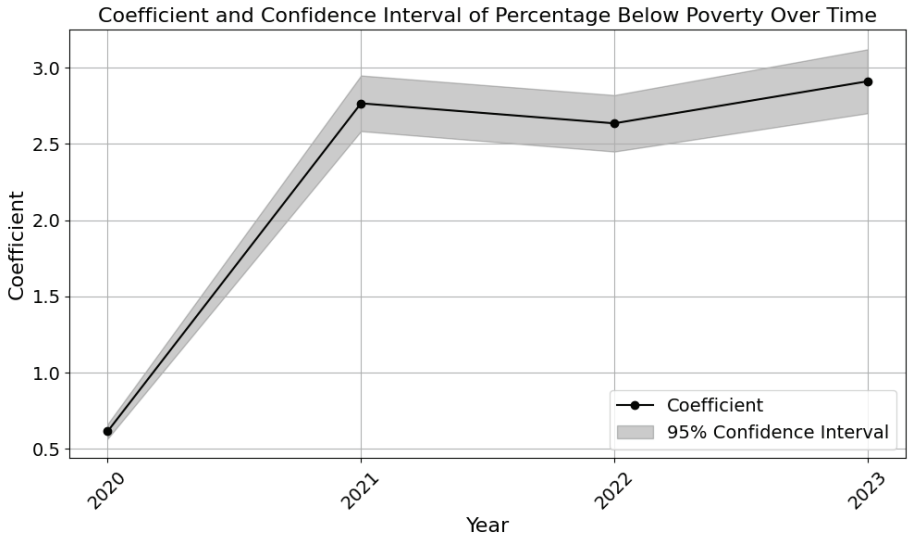


Figure 22. Coefficients for Percentage Below Poverty in simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.



Figure 23. Coefficients for Unemployment Rate for simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.

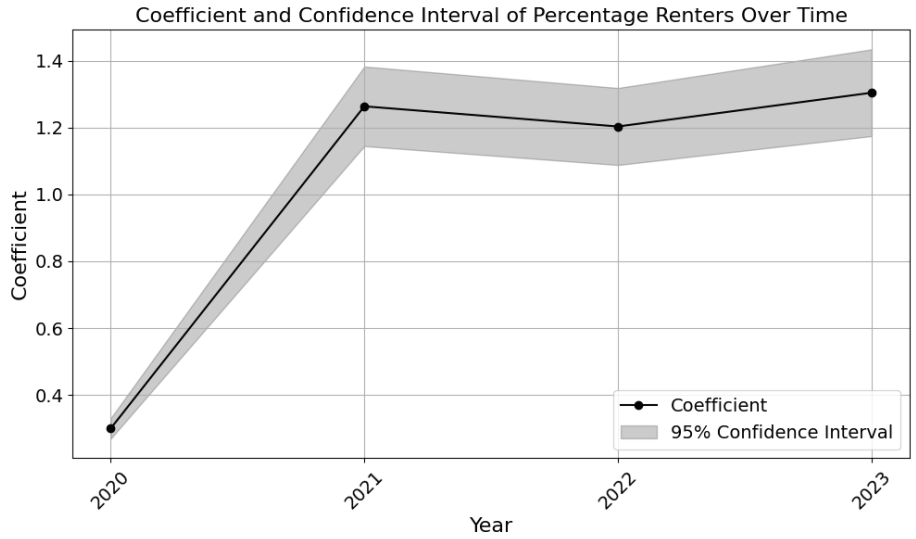


Figure 24. Coefficients for Percentage Renters in simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.

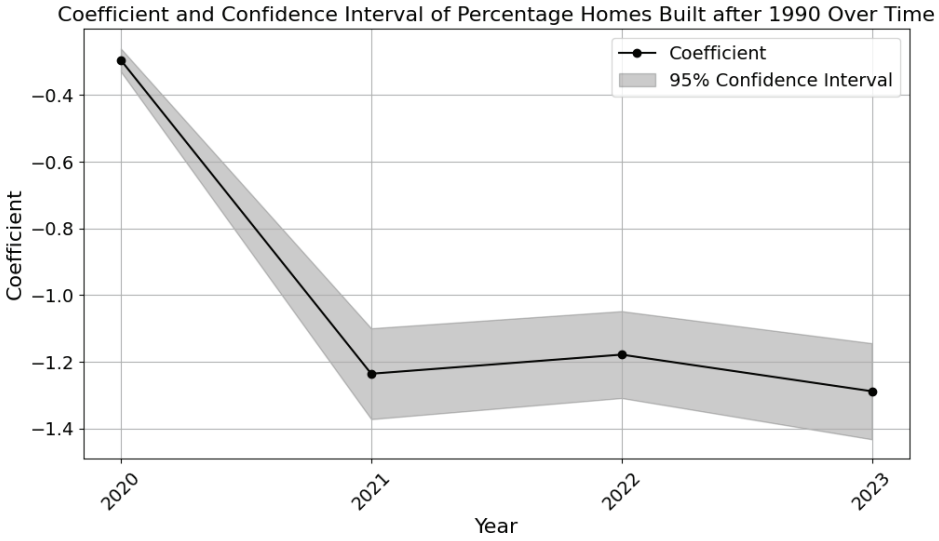


Figure 25. Coefficients for Percentage of Homes Built after 1990 in simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.

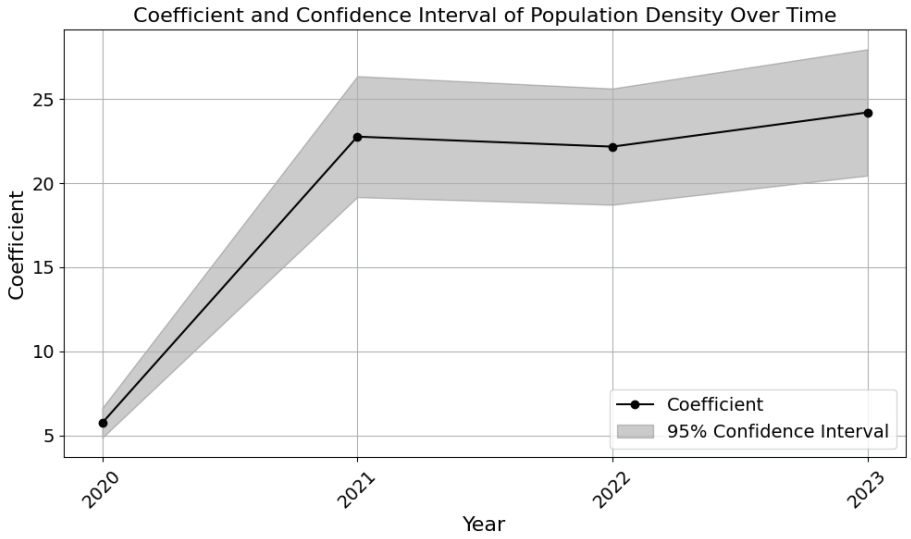


Figure 26. Coefficients for Population Density (in 1000 households per square mile) for simple linear regression models of disconnection rate (disconnections per 1000 households) in each year from 2020 through 2023.

Multiple Linear Regression Results

After assessing the individual relationship that each independent variable has with disconnection rates, we performed a multiple regression to consider potential confounding between variables. Simple linear regression does not consider overlapping influences that correlated independent variables may have on a dependent variable, so while it provides a baseline to understand the relationship between variables, it may over- or underestimate the effect of an independent variable on the dependent variable. By controlling for the effect of other factors on the disconnection rate, multiple linear regression allows us to get a better estimate of an independent variable's isolated effect on the disconnection rate. We regressed census-tract-level disconnection rate data on the combined set of independent variables specified in the previous subsection, considering data from 2021[32] through 2023 together. Table 22 shows the coefficients and p-values for each independent variable included in the model, which has an R^2 value of 0.463. As Table 22 shows, all independent variables are significant at the $p < 0.05$ level in this model, indicating that they have statistically significant correlations with disconnect rate at the census tract level. When all other independent variables are held constant, the independent variables included in this model have the following effects on disconnection rate:

- Median Home Value: A $10,000 increase in a census tract's Median Home Value is associated with a decrease of approximately 1.0 disconnections per 1000 households.
- Percentage Minority Population: A one percentage-point increase in minority population is associated with an increase of approximately 1.1 disconnections per 1000 households.

[32] Disconnection data from 2020 were excluded given the moratorium in place for most of that year.

- Percentage Below Poverty Population: A one percentage-point increase in below poverty population is associated with an increase of approximately 0.6 disconnections per 1000 households.
- Unemployment Rate: A one percentage-point increase in unemployment rate is associated with an increase of approximately 0.8 disconnections per 1000 households.
- Percentage Renters: A one percentage-point increase in the percentage of renters is associated with an increase of approximately 0.2 disconnections per 1000 households.
- Percentage of Homes Built after 1990: A one percentage-point increase in percentage of homes built after 1990 is associated with a decrease of approximately 0.3 disconnections per 1000 households.
- Population Density: An increase of 1000 households per square mile is associated with a decrease of approximately 6.3 disconnections per 1000 households.

Percentage Minority Population in a census tract is statistically significant when other socioeconomic and demographic characteristics are controlled for, which suggests that there are disparities in disconnection rate that cannot be explained by poverty, employment status, or the other independent variables included in this model. It is also notable that Percentage Minority Population has a greater correlation with disconnection rate than some other independent variables, including Percentage Below Poverty and Unemployment Rate, which are and would be expected to be positively correlated with disconnection rate.

The direction of the correlations between each independent variable and the disconnection rate are the same as in the simple linear regression models previously discussed, with one exception: Population Density. In the simple linear regression, an increase of 1000 households per square mile was associated with an increase of approximately 23 disconnections per 1000 households. In this multiple linear regression, the same increase in population density is associated with a decrease of approximately 6 disconnections per 1000 households. The multiple linear regression includes controls for socioeconomic and demographic characteristics that are not controlled for in the simple linear regression model, indicating that increasing Population Density is not associated with higher disconnection rates once contextual factors are accounted for.

Table 22. Coefficients and standard error for independent variables from a multiple linear regression on disconnection rate (disconnections per 1000 households). * denotes significance at the $p < 0.05$ level.

Variable	Coefficient	Standard Error
Intercept	43.814*	1.971
Median Home Value (per $10,000)	-1.013*	0.078
Percentage Minority	1.085*	0.035
Percentage Below Poverty	0.625*	0.073
Unemployment Rate	0.751*	0.123
Percentage Renters	0.208*	0.040
Percentage Homes Built after 1990	-0.312*	0.036
Population Density	-6.298*	0.983

Figure 27 shows Pearson's correlation coefficient for each pair of independent variables, which ranges from -1 to 1 and indicates the strength and direction of the linear relationship between two variables: a value of -1 indicates that two variables have a perfect negative linear correlation; a value of 1 indicates that two variables have a perfect positive linear correlation; and a value of 0 indicates that there is no linear relationship between the two variables. A number of independent variables have moderate correlations: Percentage Renters and Percentage Minority Population have a coefficient of 0.59; Percentage Minority Population and Percentage Below Poverty have a correlation coefficient of 0.6; and Percentage Below Poverty and Percentage Renters have a correlation coefficient of 0.64. Many of the population characteristics have moderately high correlations (~0.6), which explains the reductions in the coefficient values in the multiple regression compared to the single regressions. These variables nevertheless remain statistically significant in the regression, indicating each variable still adds distinct value to the model despite its correlations with other independent variables.



Figure 27. Correlation matrix showing Pearson's correlation coefficient for each pair of independent variables included in the multiple linear regression model of disconnection rate.

We also fit separate multiple linear regression models to each year of disconnection data from 2020 through 2023. Table 23 shows the overall model fit statistics. The F-statistic for each year's regression model tests whether the included predictors jointly explain significant variation in disconnection rates. Across all years (2020–2023), the F-statistics were statistically significant, indicating that the models had explanatory power beyond random chance and that the predictors, taken together, were useful in modeling disconnection patterns at the census tract level. The F-statistic having a smaller value in 2020 compared to the subsequent years highlights the previous observation that the independent variables have less explanatory power for this year, although they were nevertheless statistically significant. The coefficients and p-values for the predictors for these models are reported in Table 24. The model fits similarly well, with respect to explained variability (R^2), for 2021 to 2023. The model does not fit as well when regressed on 2020 data, which further supports the single variate regression results that there may be a potentially significant time-based effect, specifically for the year 2020, that is not being accounted for in the models. For 2020, unemployment rate is also not significant, though it remains significant in the subsequent regression years. The following section explores whether this observation is also related to the aforementioned time-based effect.

Table 23. Multiple Linear Regression by Year Overall Fit Statistics with F-statistic, P-value, and R^2

Year	F-statistic	p-Value	R^2
2020	191.002	0.000	0.544
2021	300.513	0.000	0.647
2022	305.438	0.000	0.652
2023	304.375	0.000	0.651

Table 24. Multiple Linear Regressions fit for each year with predictor coefficients, standard errors and p-values with significance p < 0.05 indicated by *

Year	Variable	Coefficient	Standard Error
2020	const	17.004*	0.980
	Median Home Value (per $10,000)	-0.461*	0.048
	Percentage Minority	0.208*	0.017
	Percentage Below Poverty	0.114*	0.036
	Unemployment Rate	0.045	0.062
	Percentage Renters	0.065*	0.020
	Percentage Homes Built after 1990	-0.070*	0.018
	Population Density	-1.216*	0.482
2021	const	44.877*	3.448
	Median Home Value (per $10,000)	-1.240*	0.159
	Percentage Minority	0.979*	0.059
	Percentage Below Poverty	0.737*	0.122
	Unemployment Rate	0.660*	0.209

Year	Variable	Coefficient	Standard Error
	Percentage Renters	0.210	0.068
	Percentage Homes Built after 1990	-0.307	0.061
	Population Density	-6.781	1.673
2022	const	44.569	3.213
	Median Home Value (per $10,000)	-1.105	0.127
	Percentage Minority	1.020	0.057
	Percentage Below Poverty	0.461	0.119
	Unemployment Rate	0.788	0.194
	Percentage Renters	0.232	0.064
	Percentage Homes Built after 1990	-0.282	0.058
	Population Density	-6.023	1.593
2023	const	50.187	3.646
	Median Home Value (per $10,000)	-1.197	0.135
	Percentage Minority	1.213	0.065
	Percentage Below Poverty	0.463	0.133
	Unemployment Rate	0.953	0.230
	Percentage Renters	0.211	0.072
	Percentage Homes Built after 1990	-0.263	0.064
	Population Density	-5.175	1.767

Panel Linear Regression Results

The panel linear regression implemented takes into consideration potential fixed effects for census tracts in a particular county and year, thereby producing more refined coefficient estimates than the multiple linear regression discussed in the previous subsection. Only data for 2021 through 2023 were considered in this regression; data for 2020 were excluded given the moratorium on disconnections in place for most of that year. Table 25 shows the coefficients for each independent variable in a model that considers both year and county-level fixed effects. We observe that Unemployment Rate is not statistically significant at the $p < 0.05$ level when temporal and county-level trends are considered. The remaining independent variables are statistically significant with the following effects on disconnection rates when all other independent variables, as well as county and year factors, are held constant:

- Median Home Value: A $10,000 increase in a census tract's Median Home Value is associated with a decrease of approximately 1.2 disconnections per 1000 households.
- Percentage Minority Population: A one percentage-point increase in minority population is associated with an increase of 1.0 disconnections per 1000 households.
- Percentage Below Poverty Population: A one percentage-point increase in below poverty population is associated with an increase of approximately 0.6 disconnections per 1000 households.
- Percentage Renters: A one percentage-point increase in the percentage of renters is associated with an increase of approximately 0.2 disconnections per 1000 households.

- Percentage of Homes Built after 1990: A one percentage-point increase in percentage of homes built after 1990 is associated with a decrease of approximately 0.2 disconnections per 1000 households.
- Population Density: An increase of 1000 households per square mile is associated with a decrease of approximately 7.0 disconnections per 1000 households.

As we observed in the previous subsection, Percentage Minority Population in a census tract is statistically significant and positively correlated with disconnection rate when other socioeconomic and demographic characteristics are controlled for: this observation suggests that disparities in disconnection rate exist that cannot be explained by poverty, employment status, or the other independent variables included in this model. It is also notable that Percentage Minority Population has a greater correlation with on disconnection rate than Percentage Below Poverty Population, which would be expected to be positively correlated with disconnection rate. Median Home Value and the Percentage of Homes Built after 1990 are statistically significant and negatively correlated with disconnection rate, suggesting that census tracts with newer and more expensive homes tend to experience lower disconnection rates than other census tracts when all other independent variables, as well as county and year factors, are held constant.

Figure 28 shows how the time fixed effect varies from 2021 through 2023. The magnitude of the effect is largest for 2023. The fixed effect value is negative in 2021 and less negative in 2022, indicating that there was a reduction in the disconnection rate across all census tracts in Consumers service territory in those years, but that the magnitude of that reduction was decreasing over time. This may reflect the gradual discontinuation of the disconnection moratorium that was in place in 2020.

Table 25. Panel regression model for disconnection rate (disconnections per 1000 households) considering year and county-level fixed effects: coefficients for each independent variable and standard errors.
* indicates $p < 0.05$.

Variable	Coefficient	Standard Error
Intercept	46.937*	10.008
Median Home Value (per $10,000)	-1.175*	0.349
Percentage Minority	1.001*	0.139
Percentage Below Poverty	0.634*	0.175
Unemployment Rate	0.416	0.453
Percentage Renters	0.239*	0.068
Percentage Homes Built after 1990	-0.211*	0.062
Population Density	-6.969*	1.492

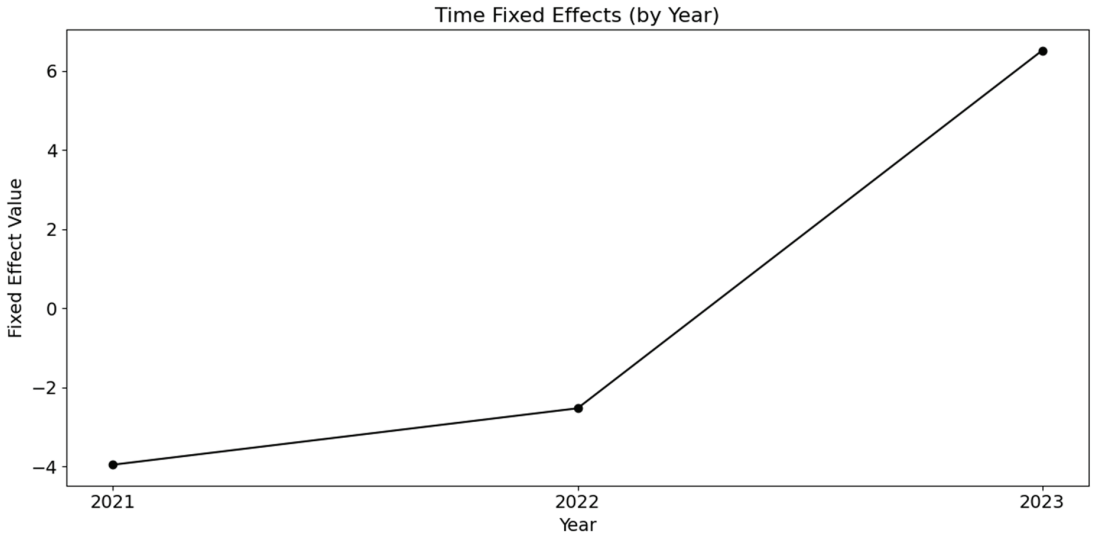


Figure 28. Time fixed-effect values for each year from 2021 through 2023.

Assessing the Relationship Between Disconnection Rates and Reliability

In addition to analyzing the influence of socioeconomic and demographic characteristics on disconnection rates and reliability, we also wanted to understand if census tracts that experience worse reliability also experience higher rates of disconnection. We investigated this question in two ways: (1) by implementing simple linear regression models, using each reliability metric as a predictor of disconnection rate at the 2020-census-tract level; and (2) comparing the average disconnection rate of census tracts with the worst reliability and all other census tracts, using the binary difference-in-means t-test.

Figure 29 through Figure 32 show scatter plots with best-fit lines from simple linear regressions for SAIDI and SAIFI (with and without MEDs) data for each year from 2020 through 2024. The R^2 values for each simple linear regression model are also shown. These measures of reliability seem to be poor predictors for disconnection rate, with the largest R^2 values across all regressions being 0.04. We observed similar results for all other reliability metrics regressed against disconnection rates as well.

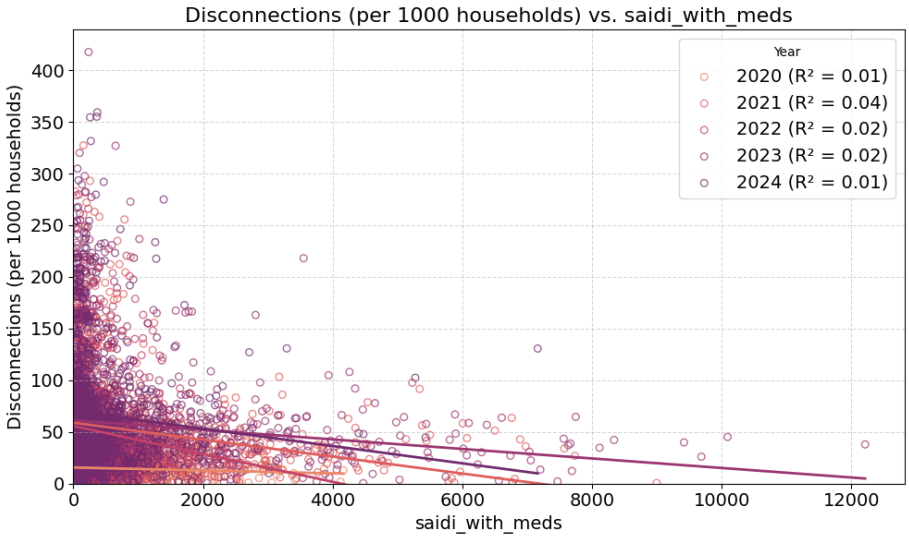


Figure 29. Disconnection rate (disconnections per 1000 households) versus SAIDI including MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

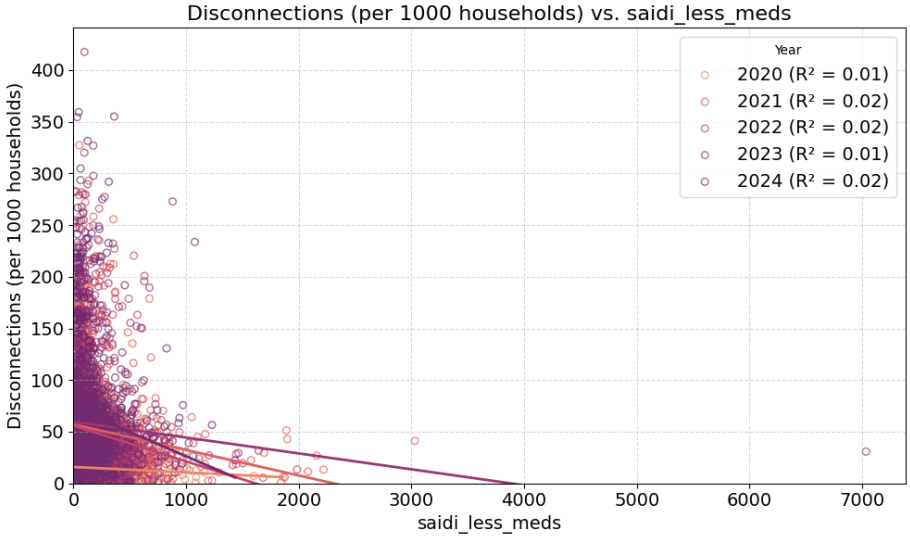


Figure 30. Disconnection rate (disconnections per 1000 households) versus SAIDI excluding MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

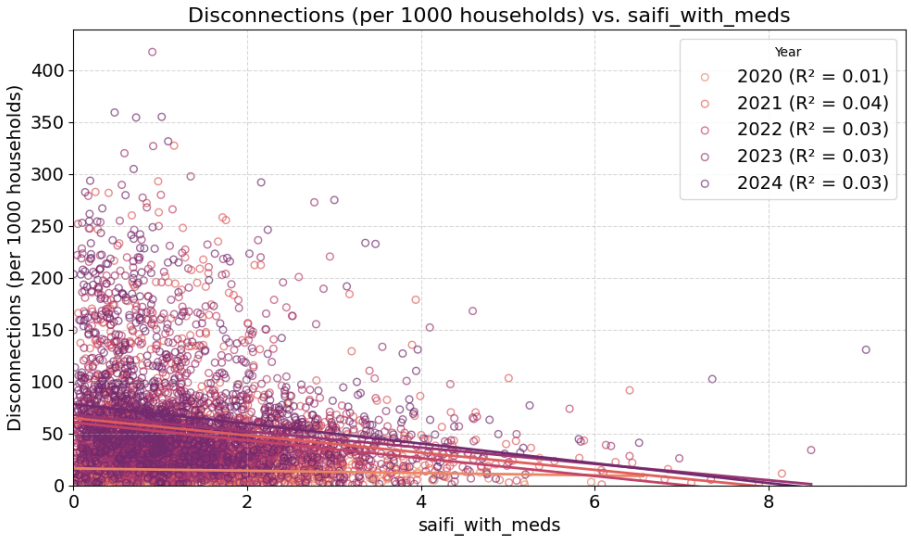


Figure 31. Disconnection rate (disconnections per 1000 households) versus SAIFI including MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

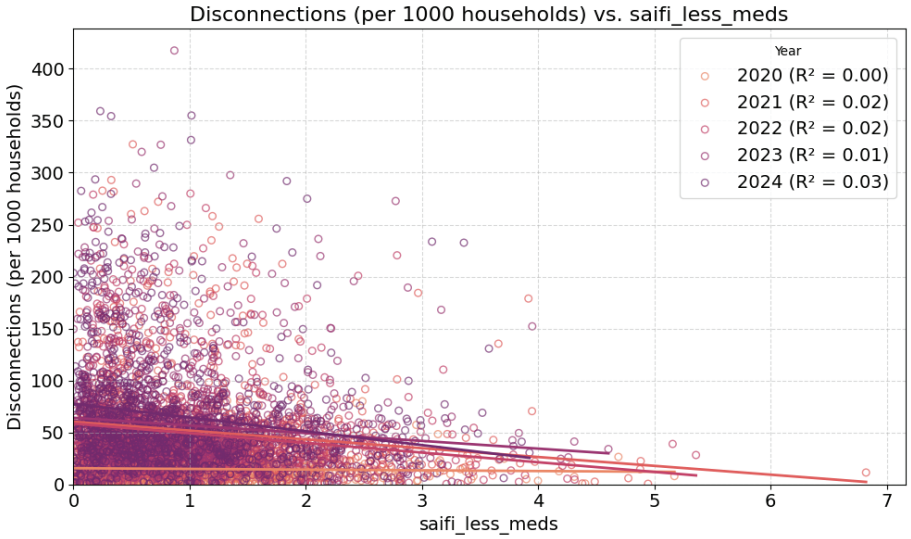


Figure 32. Disconnection rate (disconnections per 1000 households) versus SAIFI excluding MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

We compared the average disconnection rates for the census tracts with the worst reliability (according to each reliability metric) and all other census tracts to understand any potential disparities in disconnections among the groups. The 10% of census tracts with the worst reliability according to a particular reliability metric were classified as Vulnerable, while all other census tracts were considered Non-Vulnerable. The average disconnection rate for each group was calculated, as well as the difference in the averages between the two groups. A positive difference indicated that non-vulnerable census tracts have worse disconnection rates and a negative difference indicated that the vulnerable census tracts have worse disconnection rates. A difference-in-means t-test was also performed to assess the statistical significance of the differences in average disconnection rates between the two groups of census tracts. The results of this analysis are shown in Table 26. This comparison was not performed on the basis of CEMI-10 for 2020 through 2023 due to sparse data.

When statistically significant differences in the average disconnection rate of census tracts with the worst reliability and all other census tracts exist, it is consistently the census tracts with the worst reliability that have, on average, lower disconnection rates than all other census tracts. Census tracts with worse reliability, on average, have statistically significant *lower* disconnection rates than their counterparts when reliability is measured with SAIDI (with and without MEDs), SAIFI (excluding and including MEDs); CELID-5; CEMI-4, -5, and -7; and Unique Customers with an Interruption and Total Customer Interruptions. There were no statistically significant differences for CAIDI (excluding and including MEDs), CELID-24, CEMI-10, and percentage restorations in various weather conditions (in 8, 24, 36, and 48 hours). This analysis therefore shows no evidence that census tracts with the worst reliability consistently experience statistically significant, higher disconnection rates than other census tracts. We also repeated this analysis with the 20% of census tracts with the worst reliability classified as Vulnerable, while all other census tracts were classified as Non-Vulnerable. The results of this repeated analysis (not shown) are consistent with those summarized in Table 26.

Table 26. Comparison of census-tract-level disconnection rates for each year from 2020 through 2024 averaged for the 10% of census tracts with the worst reliability per each metric (the Vulnerable group) and all other census tracts within Consumers service territory (the Non-Vulnerable group). Significance is assessed at $\alpha = 0.05$.

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
Unique Customers with an Interruption	2020	1.52E+01	1.23E+01	2.84E+00	8.59E-05	TRUE	Non-vulnerable
	2021	5.23E+01	4.11E+01	1.13E+01	8.98E-07	TRUE	Non-vulnerable
	2022	5.04E+01	4.14E+01	8.97E+00	2.02E-04	TRUE	Non-vulnerable
	2023	5.81E+01	4.59E+01	1.22E+01	3.59E-05	TRUE	Non-vulnerable
	2024	6.71E+01	5.39E+01	1.32E+01	5.14E-05	TRUE	Non-vulnerable

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
Total Customer Interruptions	2020	1.49E+01	1.47E+01	1.51E-01	8.69E-01	FALSE	N/A
	2021	5.27E+01	3.78E+01	1.50E+01	2.11E-10	TRUE	Non-vulnerable
	2022	5.08E+01	3.80E+01	1.28E+01	1.14E-07	TRUE	Non-vulnerable
	2023	5.86E+01	4.16E+01	1.69E+01	5.44E-09	TRUE	Non-vulnerable
	2024	6.72E+01	5.31E+01	1.41E+01	1.79E-06	TRUE	Non-vulnerable
SAIDI including MEDS	2020	1.50E+01	1.38E+01	1.15E+00	2.43E-01	FALSE	N/A
	2021	5.31E+01	3.37E+01	1.94E+01	1.73E-13	TRUE	Non-vulnerable
	2022	5.06E+01	3.95E+01	1.11E+01	3.59E-04	TRUE	Non-vulnerable
	2023	5.85E+01	4.19E+01	1.66E+01	6.05E-07	TRUE	Non-vulnerable
	2024	6.68E+01	5.67E+01	1.01E+01	2.22E-02	TRUE	Non-vulnerable
SAIDI excluding MEDs	2020	1.52E+01	1.20E+01	3.17E+00	1.09E-04	TRUE	Non-vulnerable
	2021	5.28E+01	3.57E+01	1.72E+01	7.81E-09	TRUE	Non-vulnerable
	2022	5.09E+01	3.60E+01	1.49E+01	1.96E-04	TRUE	Non-vulnerable
	2023	5.83E+01	4.37E+01	1.46E+01	1.08E-03	TRUE	Non-vulnerable
	2024	6.74E+01	5.10E+01	1.63E+01	6.49E-04	TRUE	Non-vulnerable
SAIFI including MEDs	2020	1.51E+01	1.29E+01	2.24E+00	2.36E-02	TRUE	Non-vulnerable
	2021	5.29E+01	3.52E+01	1.78E+01	3.46E-07	TRUE	Non-vulnerable
	2022	5.08E+01	3.74E+01	1.33E+01	3.18E-04	TRUE	Non-vulnerable
	2023	5.87E+01	3.98E+01	1.89E+01	3.93E-06	TRUE	Non-vulnerable
	2024	6.73E+01	5.17E+01	1.56E+01	8.75E-04	TRUE	Non-vulnerable
SAIFI excluding MEDs	2020	1.48E+01	1.55E+01	-7.07E-01	5.92E-01	FALSE	N/A
	2021	5.31E+01	3.34E+01	1.96E+01	5.58E-09	TRUE	Non-vulnerable
	2022	5.08E+01	3.75E+01	1.33E+01	1.01E-03	TRUE	Non-vulnerable
	2023	5.78E+01	4.77E+01	1.01E+01	4.10E-02	TRUE	Non-vulnerable
	2024	6.74E+01	5.11E+01	1.63E+01	6.38E-04	TRUE	Non-vulnerable
CAIDI including MEDs	2020	1.46E+01	1.73E+01	-2.66E+00	2.85E-02	TRUE	Vulnerable
	2021	5.25E+01	3.95E+01	1.30E+01	4.30E-05	TRUE	Non-vulnerable
	2022	4.98E+01	4.61E+01	3.78E+00	2.62E-01	FALSE	N/A
	2023	5.83E+01	4.38E+01	1.44E+01	2.58E-05	TRUE	Non-vulnerable
	2024	6.52E+01	7.04E+01	-5.17E+00	3.63E-01	FALSE	N/A
CAIDI excluding MEDs	2020	1.49E+01	1.46E+01	2.60E-01	8.09E-01	FALSE	N/A
	2021	5.20E+01	4.36E+01	8.37E+00	2.54E-02	TRUE	Non-vulnerable
	2022	4.96E+01	4.82E+01	1.38E+00	7.73E-01	FALSE	N/A
	2023	5.64E+01	6.01E+01	-3.68E+00	5.20E-01	FALSE	N/A
	2024	6.57E+01	6.61E+01	-3.54E-01	9.57E-01	FALSE	N/A
CEMI-4	2020	1.50E+01	1.37E+01	1.32E+00	1.94E-01	FALSE	N/A

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
	2021	5.32E+01	3.30E+01	2.02E+01	8.66E-11	TRUE	Non-vulnerable
	2022	5.11E+01	3.48E+01	1.63E+01	5.13E-07	TRUE	Non-vulnerable
	2023	5.90E+01	3.77E+01	2.13E+01	3.27E-11	TRUE	Non-vulnerable
	2024	6.72E+01	5.32E+01	1.40E+01	1.60E-03	TRUE	Non-vulnerable
CEMI-5	2020	1.49E+01	1.43E+01	6.30E-01	5.90E-01	FALSE	N/A
	2021	5.31E+01	3.36E+01	1.96E+01	1.98E-10	TRUE	Non-vulnerable
	2022	5.10E+01	3.61E+01	1.48E+01	1.95E-06	TRUE	Non-vulnerable
	2023	5.89E+01	3.82E+01	2.08E+01	4.90E-11	TRUE	Non-vulnerable
	2024	6.75E+01	5.04E+01	1.71E+01	5.88E-05	TRUE	Non-vulnerable
CEMI-7	2020	1.50E+01	1.39E+01	1.13E+00	3.10E-01	FALSE	N/A
	2021	5.31E+01	3.47E+01	1.83E+01	5.40E-11	TRUE	Non-vulnerable
	2022	5.11E+01	3.51E+01	1.60E+01	1.37E-08	TRUE	Non-vulnerable
	2023	5.88E+01	3.97E+01	1.91E+01	3.01E-09	TRUE	Non-vulnerable
	2024	6.76E+01	4.92E+01	1.84E+01	2.25E-08	TRUE	Non-vulnerable
CEMI-10	2024	6.76E+01	5.00E+01	1.75E+01	1.61E-07	TRUE	Non-vulnerable
CELID-5	2020	1.50E+01	1.43E+01	6.90E-01	4.84E-01	FALSE	N/A
	2021	5.30E+01	3.42E+01	1.88E+01	6.84E-10	TRUE	Non-vulnerable
	2022	5.07E+01	3.83E+01	1.23E+01	4.85E-04	TRUE	Non-vulnerable
	2023	5.87E+01	3.95E+01	1.92E+01	2.93E-08	TRUE	Non-vulnerable
	2024	6.74E+01	5.07E+01	1.67E+01	6.64E-05	TRUE	Non-vulnerable
CELID-24	2020	1.49E+01	1.44E+01	5.05E-01	6.21E-01	FALSE	N/A
	2021	5.31E+01	3.36E+01	1.95E+01	6.62E-13	TRUE	Non-vulnerable
	2022	4.99E+01	4.51E+01	4.80E+00	1.62E-01	FALSE	N/A
	2023	5.86E+01	4.04E+01	1.83E+01	8.82E-09	TRUE	Non-vulnerable
	2024	6.63E+01	6.12E+01	5.08E+00	2.54E-01	FALSE	N/A
Percent of all-weather restorations made within 36 hours	2020	1.46E+01	1.76E+01	-3.02E+00	1.02E-02	TRUE	Vulnerable
	2021	5.21E+01	4.27E+01	9.44E+00	2.01E-02	TRUE	Non-vulnerable
	2022	5.06E+01	3.97E+01	1.09E+01	5.04E-04	TRUE	Non-vulnerable
	2023	5.71E+01	5.39E+01	3.17E+00	4.43E-01	FALSE	N/A
	2024	6.55E+01	6.82E+01	-2.68E+00	6.16E-01	FALSE	N/A
Percent of catastrophic-weather restorations made within 48 hours	2020	1.43E+01	2.04E+01	-6.03E+00	5.66E-05	TRUE	Vulnerable
	2021	5.04E+01	5.91E+01	-8.72E+00	7.83E-02	FALSE	N/A
	2022	4.97E+01	4.60E+01	3.70E+00	4.11E-01	FALSE	N/A
	2023	5.64E+01	6.20E+01	-5.62E+00	4.13E-01	FALSE	N/A
	2024	6.50E+01	7.42E+01	-9.18E+00	1.74E-01	FALSE	N/A
Percent of normal-weather restorations made within 8 hours	2020	1.50E+01	1.38E+01	1.25E+00	2.06E-01	FALSE	N/A
	2021	5.17E+01	4.66E+01	5.06E+00	2.21E-01	FALSE	N/A
	2022	4.90E+01	5.33E+01	-4.29E+00	3.90E-01	FALSE	N/A
	2023	5.65E+01	5.95E+01	-3.00E+00	5.96E-01	FALSE	N/A
	2024	6.50E+01	7.23E+01	-7.28E+00	2.87E-01	FALSE	N/A

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
Percent of gray-sky-weather restorations made within 24 hours	2020	1.49E+01	1.43E+01	6.38E-01	5.54E-01	FALSE	N/A
	2021	5.03E+01	5.89E+01	-8.53E+00	1.36E-01	FALSE	N/A
	2022	4.92E+01	5.20E+01	-2.84E+00	5.40E-01	FALSE	N/A
	2023	5.67E+01	5.81E+01	-1.40E+00	7.72E-01	FALSE	N/A
	2024	6.53E+01	7.01E+01	-4.74E+00	4.62E-01	FALSE	N/A

Summary of Residential Disconnection Regression Analysis Results

A panel linear regression of census-tract-level disconnection rates on different demographic and economic characteristics showed that Percentage Minority Population is statistically significant and positively correlated with disconnection rate when other socioeconomic and demographic characteristics (namely, Median Home Value, Percentage Below Poverty Population, Unemployment Rate, Percentage Renters, Percentage Homes Built after 1990, and Population Density) are controlled for. This observation suggests that disparities in Minority Population disconnection rates exist that cannot be explained by poverty or employment status, which we would expect to be correlated with residential disconnections due to non-payment. The coefficients of the panel linear regression indicate that Percentage Minority Population has a greater correlation with disconnection rate than Percentage Below Poverty Population: when all other variables as well as county-level and year factors are held constant, a one percentage-point increase in Percentage Minority Population is associated with an increase of 1.0 disconnections per 1000 households, while a one percentage-point increase in Percentage Below Poverty Population is associated with an increase of approximately 0.6 disconnections per 1000 households.

Median Home Value and the Percentage of Homes Built after 1990 are statistically significant and negatively correlated with disconnection rate, suggesting that census tracts with newer and more expensive homes tend to experience lower disconnection rates than other census tracts when all other independent variables, as well as county and year factors, are held constant. In contrast, Percentage Renters has a statistically significant and positive correlation with disconnection rate, indicating that census tracts in which a greater proportion of the population rents rather than owns their home tend to experience higher disconnection rates than other census tracts when all other independent variables and county and year factors are held constant. This may indicate an association between renting and economic insecurity.

A comparison of average disconnection rates among the 10% of census tracts with the worst reliability (by each of the 18 reliability metrics provided) and all other census tracts indicated that when statistically significant differences in the average disconnection rates of these two groups of census tracts exist, it is almost always the census tracts with the worst reliability that have lower average disconnection rates than the rest of the census tracts.

Discussion and Conclusions

To assess whether disparities exist in the reliability experienced by EJ and non-EJ communities in Consumers service territory, as well as other potentially vulnerable communities of interest, we conducted three analyses of reliability data from 2020 through 2024:

1. Comparisons of the average reliability of EJ and Non-EJ census tracts; Urban and Rural census tracts; Low-Income and High-Income census tracts; and High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts;
2. Census-tract-level reliability regression analyses with MiEJScreen Overall Score as an independent variable; and
3. Feeder-level reliability regression analyses with independent variables indicating whether a feeder serves EJ census tracts, whether a feeder serves Urban census tracts, whether a feeder serves Low-Income census tracts, and whether a feeder serves High-Percent-Minority-Percentile census tracts.

The results of the first two analyses suggest that EJ communities tend to experience better reliability than non-EJ communities, and that more vulnerable communities tend to have better reliability than less vulnerable ones. However, the feeder-level reliability regression analyses do provide limited evidence of disparities in the reliability – in terms of outage frequency – experienced by EJ communities relative to non-EJ communities in Consumers' service territory.

Comparisons of the average reliability in each year from 2020 through 2024 among EJ and Non-EJ; Urban and Rural; Low-Income and High-Income; and High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts show that when statistically significant differences in the average reliability of each pair of groups exist, it is consistently the EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts that have better average reliability than their counterparts. The metrics by which EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts experienced better average reliability include SAIDI and SAIFI, excluding and including MEDs; CEMI-4, -5, -7, and -10; and CELID-5 and -24.

Census-tract-level reliability regression analyses indicated that increasing MiEJScreen Overall Score tends to be associated with improving reliability, when a statistically significant correlation between the two exists and all other variables – namely Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden – as well as county and year effects are held constant. The correlation between increasing MiEJScreen Overall Score and improving reliability holds for SAIDI including MEDs; SAIFI including MEDs; CAIDI including or excluding MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Unique Customers with an Interruption; and Total Customer Interruptions. In contrast, increasing Poverty and increasing Percent Unemployed have statistically significant correlations with worsening reliability, in terms of SAIDI excluding and including MEDs as well as SAIFI excluding and including MEDs. Census tracts with higher poverty and unemployment rates tend to have longer and more frequent outages when all other variables, including MiEJScreen Overall Score, as well as county and year effects, are held constant.

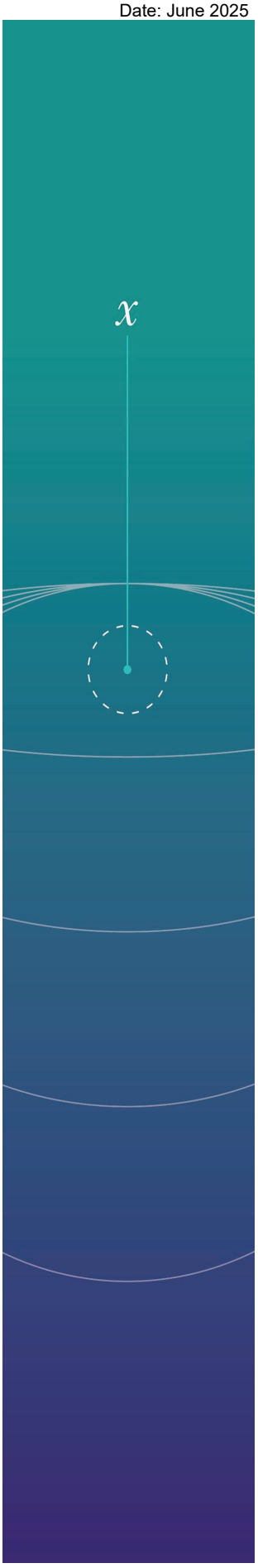
Whether a feeder serves EJ census tracts was found to have a statistically significant positive correlation with the frequency of outages: a feeder serving an EJ census tract is associated with an increase of approximately 0.1 interruptions per customer per year in SAIFI excluding MEDs compared to feeders not serving EJ census tracts when all other variables are held constant. The other variables in this regression model included feeder characteristics (Voltage, Years Since Last Trim < 7, Primary Underground Percentage, Customers per Primary Line Mile, Open-Wire Secondary Miles, Mean Canopy Cover Percentage, and Primary Miles) and characteristics of the communities served by a feeder (Urban, Low Income, and High Percent Minority Percentile). Similarly, a feeder serving an EJ census tract is associated with an increase of approximately 0.13 interruptions per customer per year in SAIFI including MEDs compared to feeders not serving EJ census tracts when all other variables are held constant. These results are practically significant, since the average SAIFI excluding MEDs of all feeders in Consumers' system is approximately 1.0 interruptions per customer per year, while the average SAIFI including MEDs of all feeders is approximately 1.4 interruptions per customer per year. Whether a feeder serves Urban, Low-Income, or High-Minority-Percentile census tracts was not found to have statistically significant correlations with SAIFI.

The phenomenological explanation for differences in the SAIFI of feeders serving EJ census tracts and feeders serving only Non-EJ census tracts remains unclear: one possible explanation is that feeders serving EJ census tracts tend to be older and therefore more prone to equipment failure and resulting interruptions than those serving only Non-EJ census tracts. Feeder age data was not available for the present study and would be a logical addition to future feeder-level reliability regression analyses. Because the physical reason for differences in the outage frequencies of feeders serving EJ census tracts and those serving only Non-EJ census tracts remains unclear, measures to resolve the observed difference in outage frequency are also unclear.

We also used regression analysis to assess whether disparities exist in the residential involuntary disconnection rates of different segments of the communities served by Consumers. Residential involuntary disconnection rate is distinct from the reliability metrics included in the present study because it reflects only administrative policies and procedures rather than the physical characteristics of electric distribution infrastructure that govern outage durations and frequencies.

A panel linear regression of census-tract-level disconnection rates showed that Percentage Minority Population is statistically significant and positively correlated with disconnection rate when other socioeconomic and demographic characteristics (namely, Median Home Value, Percentage Below Poverty Population, Unemployment Rate, Percentage Renters, Percentage Homes Built after 1990, and Population Density) are controlled. In fact, Percentage Minority Population has a greater correlation with disconnection rate than Percentage Below Poverty Population: when all other variables as well as county-level and year factors are held constant, a one percentage-point increase in Percentage Minority Population is associated with an increase of 1.0 disconnections per 1000 households, while a one percentage-point increase in Percentage Below Poverty Population is associated with an increase of approximately 0.6 disconnections per 1000 households. These increases in disconnection rates are practically significant, since the average annual disconnection rate (considering all census tracts within Consumers territory) was approximately 50 disconnections per 1000 households from 2021 through 2024.

The results of the regression analysis of residential disconnection rates indicate that disparities in Minority Population disconnection rates exist that are not explained by poverty or employment status, which we would expect to be correlated with residential disconnections due to non-payment, or by the other variables controlled for in the regression model. This finding suggests a need for further study of disconnection policies and their implementation in and impacts on different communities.



Appendix A

Census-Tract-Level Reliability Regression: Supplementary Material

A. Census-Tract-Level Reliability Regression: Supplementary Material

This appendix contains the full regression results for two sets of census-tract-level reliability regression models. The first set of regression models considers MiEJScreen Overall Score as an independent variable in each of five separate models with different combinations of other controls. Each model was fitted for 18 reliability metrics, which were considered separately as dependent variables, for a total of 90 regression models. The five regression models in the first set of models are:

1. MiEJScreen Overall Score;
2. MiEJScreen Overall Score and Poverty;
3. MiEJScreen Overall Score and Median Household Income past 12 months (in $10,000 increments);
4. MiEJScreen Overall Score and Population Density (in increments of 100 people per square mile); and
5. MiEJScreen Overall Score, Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden.

The second set of regression models considers Percent Minority Percentile as an independent variable in each of five separate models with different combinations of other controls. Each model was fitted for the same 90 reliability metrics, for an additional 90 regression models. The five regression models in the second set of models are:

1. Percent Minority Percentile;
2. Percent Minority Percentile and Poverty;
3. Percent Minority Percentile and Median Household Income past 12 months (in $10,000 increments);
4. Percent Minority Percentile and Population Density (in increments of 100 people per square mile); and
5. Percent Minority Percentile, Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden.

Results for SAIDI excluding MEDs and SAIDI including MEDs are included in the main body of the report and are not reproduced here.

Census-Tract-Level Reliability Regression Results Considering MiEJScreen Overall Score

SAIFI excluding MEDs

Table A1. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI excluding MEDs (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI excluding MEDs	1	2	3	4	5
MiEJ Overall Score	-5.72e-03*** (4.99e-04)	-6.65e-03*** (6.61e-04)	-6.55e-03*** (7.53e-04)	-3.93e-03*** (6.18e-04)	-5.49e-03*** (8.29e-04)
Poverty	-	1.15e-03* (5.36e-04)	-	-	1.71e-03* (7.62e-04)
Median Household Income past 12 months	-	-	-1.22e-02 (8.21e-03)	-	4.04e-03 (9.77e-03)
Population Density	-	-	-	-3.68e-03*** (7.55e-04)	-4.13e-03*** (7.80e-04)
Percent Unemployed	-	-	-	-	1.03e-02*** (2.49e-03)
Housing Burden	-	-	-	-	-6.82e-04 (6.38e-04)

SAIFI including MEDs

Table A2. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI including MEDs (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI including MEDs	1	2	3	4	5
MiEJ Overall Score	-1.05e-02*** (6.63e-04)	-1.15e-02*** (8.77e-04)	-1.14e-02*** (9.98e-04)	-7.70e-03*** (8.20e-04)	-9.61e-03*** (1.10e-03)
Poverty	-	1.24e-03 (7.11e-04)	-	-	2.23e-03* (1.01e-03)
Median Household Income past 12 months	-	-	-1.33e-02 (1.09e-02)	-	6.66e-03 (1.30e-02)
Population Density	-	-	-	-5.83e-03*** (1.00e-03)	-6.36e-03*** (1.04e-03)
Percent Unemployed	-	-	-	-	1.39e-02*** (3.30e-03)
Housing Burden	-	-	-	-	-1.03e-03 (8.47e-04)

CAIDI excluding MEDs

Table A3. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI excluding MEDs (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI excluding MEDs	1	2	3	4	5
MiEJ Overall Score	-4.29e-01*** (7.27e-02)	-4.06e-01*** (9.40e-02)	-4.93e-01*** (1.06e-01)	-3.74e-01*** (9.03e-02)	-4.36e-01*** (1.17e-01)
Poverty	-	-3.04e-02 (7.69e-02)	-	-	-1.14e-02 (1.12e-01)
Median Household Income past 12 months	-	-	-9.69e-01 (1.16e+00)	-	-1.31e+00 (1.43e+00)
Population Density	-	-	-	-1.16e-01 (1.12e-01)	-7.47e-02 (1.16e-01)
Percent Unemployed	-	-	-	-	9.05e-01* (3.70e-01)
Housing Burden	-	-	-	-	-1.77e-01 (9.41e-02)

CAIDI including MEDs

Table A4. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI including MEDs (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI including MEDs	1	2	3	4	5
MiEJ Overall Score	-1.99e+00*** (2.53e-01)	-1.81e+00*** (3.34e-01)	-1.67e+00*** (3.78e-01)	-1.60e+00*** (3.15e-01)	-1.39e+00*** (4.21e-01)
Poverty	-	-2.25e-01 (2.70e-01)	-	-	-5.34e-02 (3.87e-01)
Median Household Income past 12 months	-	-	4.68e+00 (4.11e+00)	-	5.23e+00 (4.96e+00)
Population Density	-	-	-	-8.10e-01* (3.85e-01)	-8.07e-01* (3.98e-01)
Percent Unemployed	-	-	-	-	9.56e-01 (1.27e+00)
Housing Burden	-	-	-	-	9.99e-02 (3.24e-01)

CELID-5

Table A5. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-5 (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-5	1	2	3	4	5
MiEJ Overall Score	-2.86e-01*** (1.89e-02)	-2.77e-01*** (2.46e-02)	-2.60e-01*** (2.78e-02)	-2.25e-01*** (2.34e-02)	-2.17e-01*** (3.08e-02)
Poverty	-	-1.15e-02 (2.01e-02)	-	-	2.56e-02 (2.89e-02)
Median Household Income past 12 months	-	-	3.95e-01 (3.04e-01)	-	6.62e-01 (3.68e-01)
Population Density	-	-	-	-1.27e-01*** (2.88e-02)	-1.28e-01*** (2.98e-02)
Percent Unemployed	-	-	-	-	2.73e-01** (9.49e-02)
Housing Burden	-	-	-	-	-1.83e-02 (2.42e-02)

CELID-24

Table A6. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-24 (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-24	1	2	3	4	5
MiEJ Overall Score	-1.37e-01*** (1.28e-02)	-1.42e-01*** (1.68e-02)	-1.34e-01*** (1.90e-02)	-1.03e-01*** (1.59e-02)	-1.11e-01*** (2.11e-02)
Poverty	-	5.95e-03 (1.36e-02)	-	-	1.75e-02 (1.96e-02)
Median Household Income past 12 months	-	-	5.51e-02 (2.07e-01)	-	2.68e-01 (2.50e-01)
Population Density	-	-	-	-7.14e-02*** (1.95e-02)	-7.79e-02*** (2.02e-02)
Percent Unemployed	-	-	-	-	1.08e-01 (6.43e-02)
Housing Burden	-	-	-	-	3.51e-03 (1.64e-02)

CEMI-4

Table A7. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-4 (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-4	1	2	3	4	5
MiEJ Overall Score	-1.52e-01*** (1.05e-02)	-1.71e-01*** (1.39e-02)	-1.77e-01*** (1.58e-02)	-1.17e-01*** (1.31e-02)	-1.55e-01*** (1.75e-02)
Poverty	-	2.38e-02* (1.13e-02)	-	-	2.76e-02 (1.61e-02)
Median Household Income past 12 months	-	-	-3.72e-01* (1.73e-01)	-	-1.01e-01 (2.06e-01)
Population Density	-	-	-	-7.13e-02*** (1.60e-02)	-8.05e-02*** (1.65e-02)
Percent Unemployed	-	-	-	-	1.80e-01*** (5.27e-02)
Housing Burden	-	-	-	-	-1.00e-02 (1.35e-02)

CEMI-5

Table A8. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-5 (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-5	1	2	3	4	5
MiEJ Overall Score	-8.80e-02*** (7.54e-03)	-1.02e-01*** (9.93e-03)	-1.13e-01*** (1.13e-02)	-6.49e-02*** (9.34e-03)	-9.72e-02*** (1.24e-02)
Poverty	-	1.79e-02* (8.07e-03)	-	-	1.52e-02 (1.15e-02)
Median Household Income past 12 months	-	-	-3.63e-01** (1.23e-01)	-	-2.02e-01 (1.47e-01)
Population Density	-	-	-	-4.76e-02*** (1.14e-02)	-5.41e-02*** (1.18e-02)
Percent Unemployed	-	-	-	-	1.22e-01** (3.77e-02)
Housing Burden	-	-	-	-	-6.15e-03 (9.65e-03)

CEMI-7

Table A9. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-7 (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-7	1	2	3	4	5
MiEJ Overall Score	-2.47e-02*** (3.85e-03)	-2.89e-02*** (5.11e-03)	-3.22e-02*** (5.82e-03)	-1.81e-02*** (4.78e-03)	-2.71e-02*** (6.43e-03)
Poverty	-	5.14e-03 (4.14e-03)	-	-	7.53e-03 (5.90e-03)
Median Household Income past 12 months	-	-	-1.09e-01 (6.34e-02)	-	-6.79e-02 (7.57e-02)
Population Density	-	-	-	-1.37e-02* (5.83e-03)	-1.46e-02* (6.03e-03)
Percent Unemployed	-	-	-	-	4.11e-02* (1.93e-02)
Housing Burden	-	-	-	-	-7.56e-03 (4.94e-03)

CEMI-10

Table A10. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-10 (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-10	1	2	3	4	5
MiEJ Overall Score	-2.49e-03 (1.77e-03)	-2.95e-03 (2.35e-03)	-2.28e-03 (2.67e-03)	-1.71e-03 (2.19e-03)	-1.10e-03 (2.96e-03)
Poverty	-	5.69e-04 (1.90e-03)	-	-	4.44e-03 (2.71e-03)
Median Household Income past 12 months	-	-	2.99e-03 (2.91e-02)	-	6.93e-03 (3.48e-02)
Population Density	-	-	-	-1.59e-03 (2.68e-03)	-1.11e-03 (2.77e-03)
Percent Unemployed	-	-	-	-	3.33e-03 (8.86e-03)
Housing Burden	-	-	-	-	-5.34e-03* (2.27e-03)

Percentage of normal-weather restorations made within 8 hours

Table A11. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of normal-weather restorations made within 8 hours (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of normal-weather restorations made within 8 hours	1	2	3	4	5
MiEJ Overall Score	2.04e-03 (8.05e-03)	-6.34e-03 (1.02e-02)	1.05e-03 (1.12e-02)	5.41e-03 (9.99e-03)	2.35e-03 (1.26e-02)
Poverty	-	1.13e-02 (8.41e-03)	-	-	1.15e-02 (1.25e-02)
Median Household Income past 12 months	-	-	-1.54e-02 (1.24e-01)	-	1.07e-01 (1.57e-01)
Population Density	-	-	-	-7.14e-03 (1.25e-02)	-1.50e-02 (1.30e-02)
Percent Unemployed	-	-	-	-	-6.81e-02 (4.15e-02)
Housing Burden	-	-	-	-	1.66e-02 (1.05e-02)

Percentage of gray-sky weather restorations made within 24 hours

Table A12. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of gray-sky-weather restorations made within 24 hours (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of gray-sky-weather restorations made within 24 hours	1	2	3	4	5
MiEJ Overall Score	7.71e-03 (1.19e-02)	2.25e-03 (1.51e-02)	2.47e-02 (1.66e-02)	-8.06e-03 (1.51e-02)	8.30e-03 (1.89e-02)
Poverty	-	7.49e-03 (1.26e-02)	-	-	1.64e-02 (1.87e-02)
Median Household Income past 12 months	-	-	2.74e-01 (1.86e-01)	-	4.33e-01 (2.34e-01)
Population Density	-	-	-	3.34e-02 (1.95e-02)	2.60e-02 (2.01e-02)
Percent Unemployed	-	-	-	-	-9.37e-02 (6.20e-02)
Housing Burden	-	-	-	-	1.68e-02 (1.56e-02)

Percent of all-weather restorations made within 36 hours

Table A13. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of all-weather restorations made within 36 hours (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of all-weather restorations made within 36 hours	1	2	3	4	5
MiEJ Overall Score	2.88e-02*** (6.14e-03)	2.82e-02*** (8.06e-03)	2.58e-02** (9.07e-03)	2.09e-02** (7.65e-03)	2.16e-02* (1.02e-02)
Poverty	-	8.76e-04 (6.53e-03)	-	-	1.86e-03 (9.39e-03)
Median Household Income past 12 months	-	-	-4.44e-02 (9.86e-02)	-	-9.07e-02 (1.20e-01)
Population Density	-	-	-	1.64e-02 (9.36e-03)	1.82e-02 (9.67e-03)
Percent Unemployed	-	-	-	-	-2.81e-02 (3.09e-02)
Housing Burden	-	-	-	-	-7.31e-03 (7.86e-03)

Percentage of catastrophic-weather restorations made within 48 hours

Table A14. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of catastrophic-weather restorations made within 48 hours (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of catastrophic-weather restorations made within 48 hours	1	2	3	4	5
MiEJ Overall Score	3.46e-03 (1.72e-02)	-1.45e-02 (2.21e-02)	-9.61e-03 (2.53e-02)	-9.05e-03 (2.17e-02)	-1.58e-02 (2.89e-02)
Poverty	-	2.34e-02 (1.81e-02)	-	-	3.40e-02 (2.57e-02)
Median Household Income past 12 months	-	-	-1.98e-01 (2.81e-01)	-	-1.58e-01 (3.33e-01)
Population Density	-	-	-	2.58e-02 (2.75e-02)	2.10e-02 (2.83e-02)
Percent Unemployed	-	-	-	-	-1.77e-01 (9.10e-02)
Housing Burden	-	-	-	-	-1.06e-02 (2.18e-02)

Total Customer Interruptions

Table A15. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Total Customer Interruptions (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Total Customer Interruptions	1	2	3	4	5
MiEJ Overall Score	-2.82e+01*** (1.43e+00)	-2.51e+01*** (1.90e+00)	-2.14e+01*** (2.16e+00)	-2.04e+01*** (1.77e+00)	-1.67e+01*** (2.38e+00)
Poverty	-	-3.88e+00* (1.54e+00)	-	-	-2.44e+00 (2.17e+00)
Median Household Income past 12 months	-	-	9.86e+01*** (2.35e+01)	-	1.14e+02*** (2.79e+01)
Population Density	-	-	-	-1.60e+01*** (2.15e+00)	-1.69e+01*** (2.22e+00)
Percent Unemployed	-	-	-	-	7.87e+00 (7.10e+00)
Housing Burden	-	-	-	-	6.70e+00*** (1.82e+00)

Unique Customers with an Interruption

Table A16. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Unique Customers with an Interruption (with county-level and year fixed effects). All models include MiEJ Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Unique Customers with an Interruption	1	2	3	4	5
MiEJ Overall Score	-9.17e+00*** (4.94e-01)	-6.37e+00*** (6.51e-01)	-4.45e+00*** (7.40e-01)	-6.68e+00*** (6.10e-01)	-2.79e+00*** (8.14e-01)
Poverty	-	-3.44e+00*** (5.27e-01)	-	-	-2.74e+00*** (7.45e-01)
Median Household Income past 12 months	-	-	6.85e+01*** (8.06e+00)	-	5.94e+01*** (9.57e+00)
Population Density	-	-	-	-5.12e+00*** (7.43e-01)	-4.96e+00*** (7.62e-01)
Percent Unemployed	-	-	-	-	-5.31e+00* (2.43e+00)
Housing Burden	-	-	-	-	3.63e+00*** (6.24e-01)

Census-Tract-Level Reliability Regression Results Considering Percent Minority Percentile

SAIFI excluding MEDs

Table A17. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI excluding MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI excluding MEDs	1	2	3	4	5
Percent Minority Percentile	-4.68e-03*** (4.32e-04)	-5.17e-03*** (5.63e-04)	-4.08e-03*** (5.08e-04)	-3.13e-03*** (5.03e-04)	-4.35e-03*** (5.92e-04)
Poverty	-	7.16e-04 (5.28e-04)	-	-	3.09e-03*** (7.88e-04)
Median Household Income past 12 months	-	-	1.45e-02* (6.40e-03)	-	3.44e-02*** (8.72e-03)
Population Density	-	-	-	-4.24e-03*** (7.11e-04)	-4.48e-03*** (7.58e-04)
Percent Unemployed	-	-	-	-	1.11e-02*** (2.50e-03)
Housing Burden	-	-	-	-	-6.35e-04 (6.37e-04)

SAIFI including MEDs

Table A18. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI including MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI including MEDs	1	2	3	4	5
Percent Minority Percentile	-8.51e-03*** (5.75e-04)	-8.77e-03*** (7.49e-04)	-7.15e-03*** (6.75e-04)	-5.92e-03*** (6.69e-04)	-7.36e-03*** (7.85e-04)
Poverty	-	3.77e-04 (7.02e-04)	-	-	4.58e-03*** (1.04e-03)
Median Household Income past 12 months	-	-	3.30e-02*** (8.51e-03)	-	5.96e-02*** (1.16e-02)
Population Density	-	-	-	-7.08e-03*** (9.44e-04)	-7.07e-03*** (1.01e-03)
Percent Unemployed	-	-	-	-	1.53e-02*** (3.32e-03)
Housing Burden	-	-	-	-	-9.82e-04 (8.45e-04)

CAIDI excluding MEDs

Table A19. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI excluding MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI excluding MEDs	1	2	3	4	5
Percent Minority Percentile	-2.90e-01*** (6.36e-02)	-2.12e-01** (8.15e-02)	-2.30e-01** (7.38e-02)	-2.01e-01** (7.44e-02)	-1.69e-01 (8.69e-02)
Poverty	-	-1.16e-01 (7.64e-02)	-	-	4.36e-02 (1.16e-01)
Median Household Income past 12 months	-	-	1.48e+00 (9.28e-01)	-	1.01e+00 (1.29e+00)
Population Density	-	-	-	-2.42e-01* (1.06e-01)	-1.69e-01 (1.12e-01)
Percent Unemployed	-	-	-	-	8.69e-01* (3.72e-01)
Housing Burden	-	-	-	-	-1.96e-01* (9.43e-02)

CAIDI including MEDs

Table A20. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI including MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI including MEDs	1	2	3	4	5
Percent Minority Percentile	-1.27e+00*** (2.19e-01)	-8.02e-01** (2.81e-01)	-7.28e-01** (2.54e-01)	-7.50e-01** (2.56e-01)	-5.31e-01 (2.99e-01)
Poverty	-	-7.04e-01** (2.63e-01)	-	-	1.09e-01 (3.99e-01)
Median Household Income past 12 months	-	-	1.35e+01*** (3.20e+00)	-	1.27e+01** (4.44e+00)
Population Density	-	-	-	-1.42e+00*** (3.62e-01)	-1.09e+00** (3.86e-01)
Percent Unemployed	-	-	-	-	8.29e-01 (1.28e+00)
Housing Burden	-	-	-	-	4.03e-02 (3.24e-01)

CELID-5

Table A21. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-5 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-5	1	2	3	4	5
Percent Minority Percentile	-1.01e-01*** (1.11e-02)	-9.05e-02*** (1.43e-02)	-7.42e-02*** (1.29e-02)	-6.41e-02*** (1.30e-02)	-7.04e-02*** (1.52e-02)
Poverty	-	-1.50e-02 (1.34e-02)	-	-	4.01e-02* (2.02e-02)
Median Household Income past 12 months	-	-	6.49e-01*** (1.63e-01)	-	8.71e-01*** (2.25e-01)
Population Density	-	-	-	-9.93e-02*** (1.84e-02)	-9.19e-02*** (1.96e-02)
Percent Unemployed	-	-	-	-	1.15e-01 (6.47e-02)
Housing Burden	-	-	-	-	2.30e-03 (1.64e-02)

CELID-24

Table A22. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-24 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-24	1	2	3	4	5
Percent Minority Percentile	-1.01e-01*** (1.11e-02)	-9.05e-02*** (1.43e-02)	-7.42e-02*** (1.29e-02)	-6.41e-02*** (1.30e-02)	-7.04e-02*** (1.52e-02)
Poverty	-	-1.50e-02 (1.34e-02)	-	-	4.01e-02* (2.02e-02)
Median Household Income past 12 months	-	-	6.49e-01*** (1.63e-01)	-	8.71e-01*** (2.25e-01)
Population Density	-	-	-	-9.93e-02*** (1.84e-02)	-9.19e-02*** (1.96e-02)
Percent Unemployed	-	-	-	-	1.15e-01 (6.47e-02)
Housing Burden	-	-	-	-	2.30e-03 (1.64e-02)

CEMI-4

Table A23. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-4 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-4	1	2	3	4	5
Percent Minority Percentile	-1.21e-01*** (9.15e-03)	-1.28e-01*** (1.19e-02)	-1.06e-01*** (1.07e-02)	-8.74e-02*** (1.07e-02)	-1.09e-01*** (1.25e-02)
Poverty	-	9.64e-03 (1.12e-02)	-	-	6.21e-02*** (1.67e-02)
Median Household Income past 12 months	-	-	3.77e-01** (1.35e-01)	-	7.50e-01*** (1.85e-01)
Population Density	-	-	-	-9.22e-02*** (1.50e-02)	-9.49e-02*** (1.61e-02)
Percent Unemployed	-	-	-	-	1.96e-01*** (5.29e-02)
Housing Burden	-	-	-	-	-1.05e-02 (1.35e-02)

CEMI-5

Table A24. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-5 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-5	1	2	3	4	5
Percent Minority Percentile	-7.33e-02*** (6.54e-03)	-8.19e-02*** (8.49e-03)	-6.91e-02*** (7.67e-03)	-5.27e-02*** (7.62e-03)	-7.07e-02*** (8.96e-03)
Poverty	-	1.26e-02 (7.96e-03)	-	-	3.77e-02** (1.19e-02)
Median Household Income past 12 months	-	-	9.99e-02 (9.66e-02)	-	3.31e-01* (1.32e-01)
Population Density	-	-	-	-5.61e-02*** (1.08e-02)	-6.26e-02*** (1.15e-02)
Percent Unemployed	-	-	-	-	1.33e-01*** (3.79e-02)
Housing Burden	-	-	-	-	-6.13e-03 (9.65e-03)

CEMI-7

Table A25. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-7 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-7	1	2	3	4	5
Percent Minority Percentile	-2.18e-02*** (3.33e-03)	-2.51e-02*** (4.34e-03)	-2.12e-02*** (3.91e-03)	-1.64e-02*** (3.89e-03)	-2.18e-02*** (4.59e-03)
Poverty	-	4.83e-03 (4.07e-03)	-	-	1.45e-02* (6.10e-03)
Median Household Income past 12 months	-	-	1.44e-02 (4.93e-02)	-	8.21e-02 (6.76e-02)
Population Density	-	-	-	-1.48e-02** (5.49e-03)	-1.63e-02** (5.87e-03)
Percent Unemployed	-	-	-	-	4.56e-02* (1.93e-02)
Housing Burden	-	-	-	-	-7.31e-03 (4.94e-03)

CEMI-10

Table A26. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-10 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-10	1	2	3	4	5
Percent Minority Percentile	-3.49e-03* (1.53e-03)	-4.76e-03* (1.99e-03)	-3.57e-03* (1.79e-03)	-3.35e-03 (1.79e-03)	-4.08e-03 (2.11e-03)
Poverty	-	1.86e-03 (1.87e-03)	-	-	5.81e-03* (2.81e-03)
Median Household Income past 12 months	-	-	-1.94e-03 (2.26e-02)	-	1.39e-02 (3.11e-02)
Population Density	-	-	-	-3.84e-04 (2.52e-03)	-1.72e-04 (2.70e-03)
Percent Unemployed	-	-	-	-	5.44e-03 (8.90e-03)
Housing Burden	-	-	-	-	-4.94e-03* (2.27e-03)

Percentage of normal-weather restorations made within 8 hours

Table A27. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of normal-weather restorations made within 8 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of normal-weather restorations made within 8 hours	1	2	3	4	5
Percent Minority Percentile	-1.81e-03 (7.08e-03)	-1.16e-02 (9.00e-03)	-3.61e-03 (8.13e-03)	-9.12e-04 (8.32e-03)	-9.38e-03 (9.66e-03)
Poverty	-	1.48e-02 (8.44e-03)	-	-	1.47e-02 (1.29e-02)
Median Household Income past 12 months	-	-	-4.60e-02 (1.02e-01)	-	1.07e-01 (1.45e-01)
Population Density	-	-	-	-2.44e-03 (1.19e-02)	-1.12e-02 (1.26e-02)
Percent Unemployed	-	-	-	-	-6.06e-02 (4.18e-02)
Housing Burden	-	-	-	-	1.83e-02 (1.05e-02)

Percentage of gray-sky weather restorations made within 24 hours

Table A28. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of gray-sky-weather restorations made within 24 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of gray-sky-weather restorations made within 24 hours	1	2	3	4	5
Percent Minority Percentile	6.29e-03 (1.05e-02)	1.11e-03 (1.34e-02)	1.24e-02 (1.21e-02)	-5.07e-03 (1.25e-02)	-5.06e-03 (1.44e-02)
Poverty	-	7.99e-03 (1.27e-02)	-	-	1.77e-02 (1.92e-02)
Median Household Income past 12 months	-	-	1.58e-01 (1.53e-01)	-	3.95e-01 (2.14e-01)
Population Density	-	-	-	3.11e-02 (1.83e-02)	3.18e-02 (1.93e-02)
Percent Unemployed	-	-	-	-	-8.78e-02 (6.24e-02)
Housing Burden	-	-	-	-	1.83e-02 (1.56e-02)

Percent of all-weather restorations made within 36 hours

Table A29. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of all-weather restorations made within 36 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of all-weather restorations made within 36 hours	1	2	3	4	5
Percent Minority Percentile	1.36e-02* (5.30e-03)	5.46e-03 (6.76e-03)	4.86e-03 (6.13e-03)	2.75e-03 (6.21e-03)	3.32e-04 (7.23e-03)
Poverty	-	1.24e-02 (6.34e-03)	-	-	1.82e-03 (9.65e-03)
Median Household Income past 12 months	-	-	-2.19e-01** (7.72e-02)	-	-2.01e-01 (1.08e-01)
Population Density	-	-	-	2.96e-02*** (8.81e-03)	2.55e-02** (9.37e-03)
Percent Unemployed	-	-	-	-	-2.11e-02 (3.11e-02)
Housing Burden	-	-	-	-	-5.30e-03 (7.85e-03)

Percentage of catastrophic-weather restorations made within 48 hours

Table A30. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of catastrophic-weather restorations made within 48 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of catastrophic-weather restorations made within 48 hours	1	2	3	4	5
Percent Minority Percentile	-1.04e-02 (1.49e-02)	-3.29e-02 (1.87e-02)	-1.93e-02 (1.69e-02)	-2.40e-02 (1.75e-02)	-3.32e-02 (2.02e-02)
Poverty	-	3.48e-02* (1.77e-02)	-	-	4.45e-02 (2.65e-02)
Median Household Income past 12 months	-	-	-2.38e-01 (2.17e-01)	-	-5.29e-02 (2.95e-01)
Population Density	-	-	-	3.74e-02 (2.56e-02)	2.79e-02 (2.71e-02)
Percent Unemployed	-	-	-	-	-1.62e-01 (9.13e-02)
Housing Burden	-	-	-	-	-7.38e-03 (2.19e-02)

Total Customer Interruptions

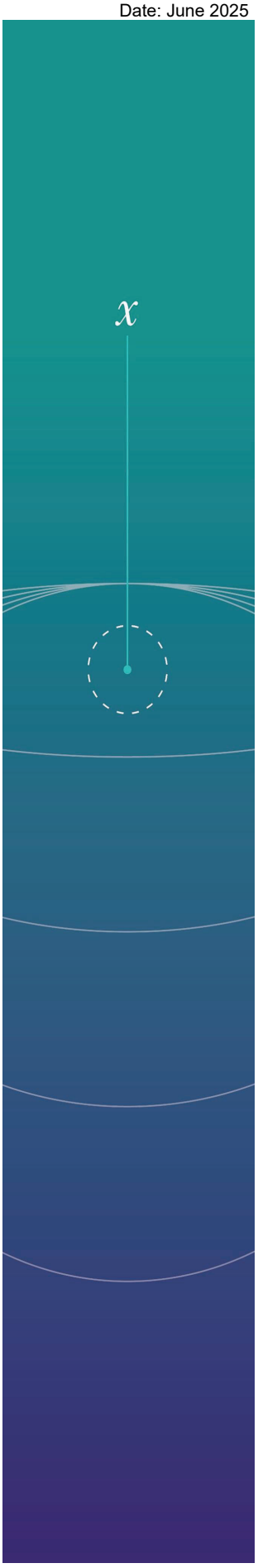
Table A31. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Total Customer Interruptions (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Total Customer Interruptions	1	2	3	4	5
Percent Minority Percentile	-2.06e+01*** (1.25e+00)	-1.49e+01*** (1.62e+00)	-1.26e+01*** (1.45e+00)	-1.26e+01*** (1.44e+00)	-1.11e+01*** (1.69e+00)
Poverty	-	-8.27e+00*** (1.52e+00)	-	-	1.07e+00 (2.25e+00)
Median Household Income past 12 months	-	-	1.90e+02*** (1.83e+01)	-	2.05e+02*** (2.49e+01)
Population Density	-	-	-	-2.16e+01*** (2.04e+00)	-1.85e+01*** (2.16e+00)
Percent Unemployed	-	-	-	-	9.22e+00 (7.13e+00)
Housing Burden	-	-	-	-	6.56e+00*** (1.82e+00)

Unique Customers with an Interruption

Table A32. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Unique Customers with an Interruption (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Unique Customers with an Interruption	1	2	3	4	5
Percent Minority Percentile	-6.35e+00*** (4.31e-01)	-2.87e+00*** (5.56e-01)	-2.76e+00*** (4.97e-01)	-3.70e+00*** (4.99e-01)	-1.67e+00** (5.80e-01)
Poverty	-	-5.10e+00*** (5.22e-01)	-	-	-2.22e+00** (7.71e-01)
Median Household Income past 12 months	-	-	8.67e+01*** (6.28e+00)	-	7.47e+01*** (8.54e+00)
Population Density	-	-	-	-7.23e+00*** (7.04e-01)	-5.30e+00*** (7.41e-01)
Percent Unemployed	-	-	-	-	-5.20e+00* (2.44e+00)
Housing Burden	-	-	-	-	3.58e+00*** (6.24e-01)



Appendix B

Feeder-Level Reliability Regression: Supplementary Material

B. Feeder-Level Reliability Regression: Supplementary Material

This appendix contains supplementary information on the feeders in Consumers' electric distribution system. Table B1 lists the ten different voltage levels and configurations represented in Consumers' electric distribution system and the percentage of the 2400 feeders at each. Figure B1 through Figure B10 map the census tracts within Consumers' service territory served by feeders of each voltage level and configuration.

Table B1. The percentage of feeders in Consumers' electric distribution system at each voltage level and configuration.

Voltage	Percentage of Feeders
4.8/8.32 kV Wye Grounded	57.1
7.2/12.47 kV Wye Grounded	24.9
14.4/24.9 kV Wye Grounded	14.1
7.2 kV Delta	1.3
14.4 kV Delta	1.0
11.0 kV Delta	0.7
13.2 kV Delta	0.4
12.0 kV Delta	0.3
4.8 kV Delta	0.3
2.4 kV Delta	0.1

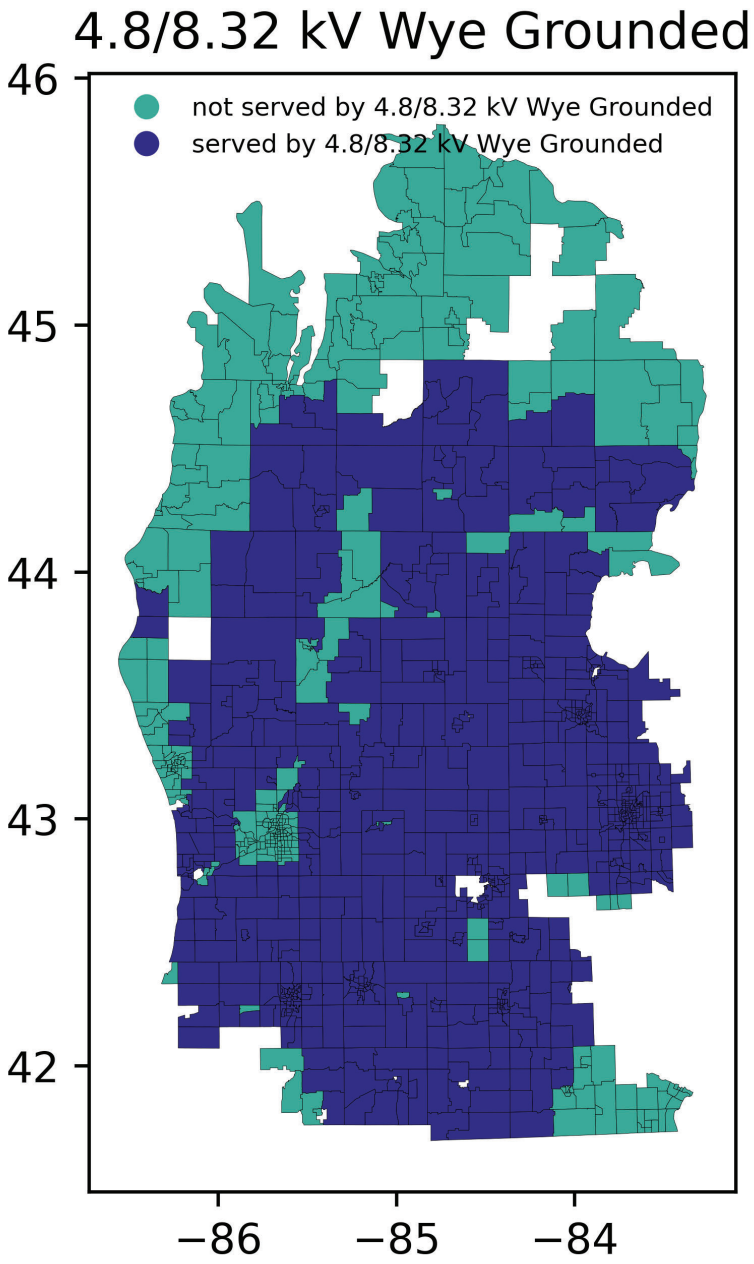


Figure B1. Map of 2010 census tracts in Consumers service territory served by 4.8/8.32 kV Wye Grounded feeders.

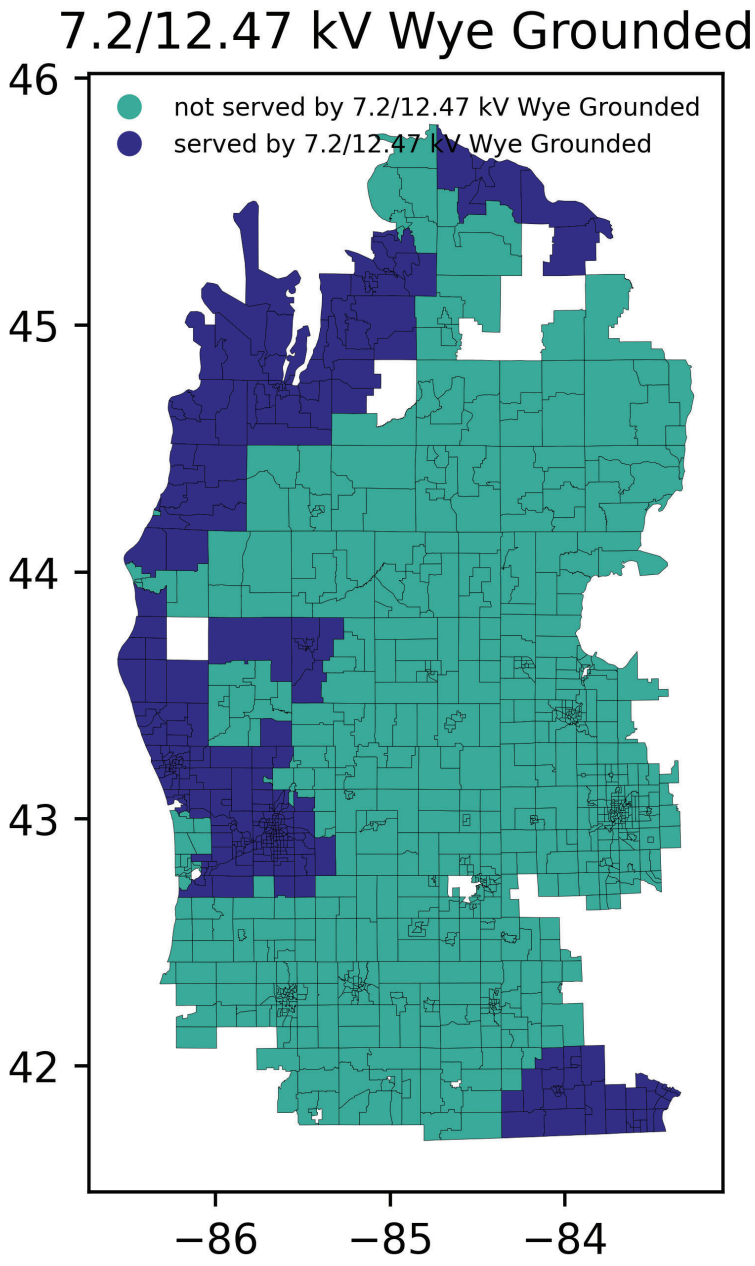


Figure B2. Map of 2010 census tracts in Consumers service territory served by 7.2/12.47 kV Wye Grounded feeders.

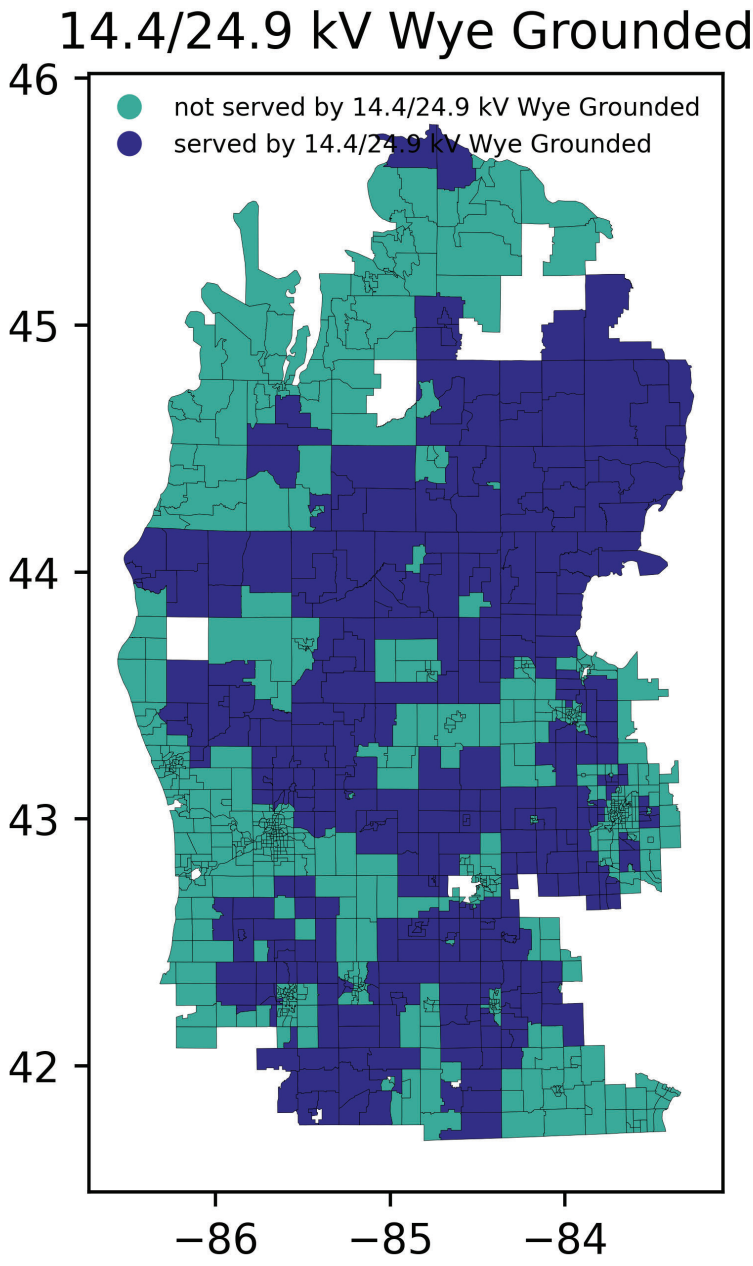


Figure B3. Map of 2010 census tracts in Consumers service territory served by 14.4/24.9 kV Wye Grounded feeders.

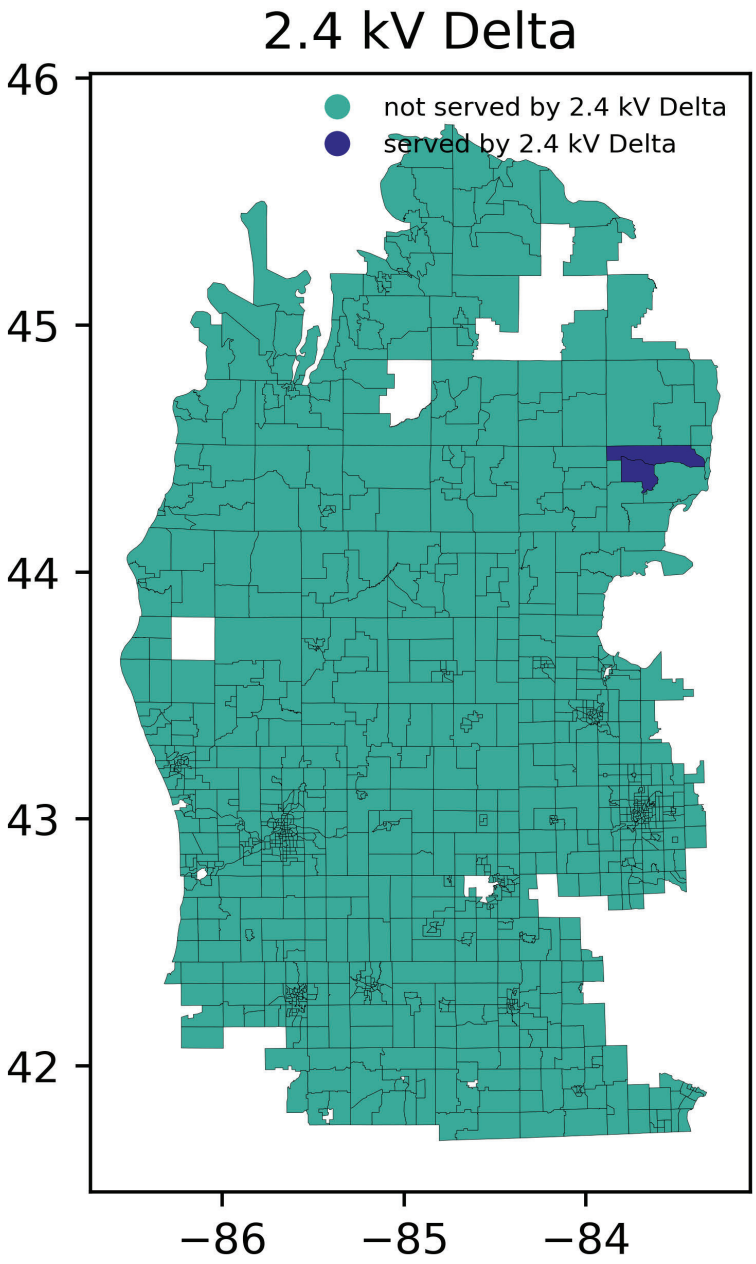


Figure B4. Map of 2010 census tracts in Consumers service territory served by 2.4 kV Delta feeders.

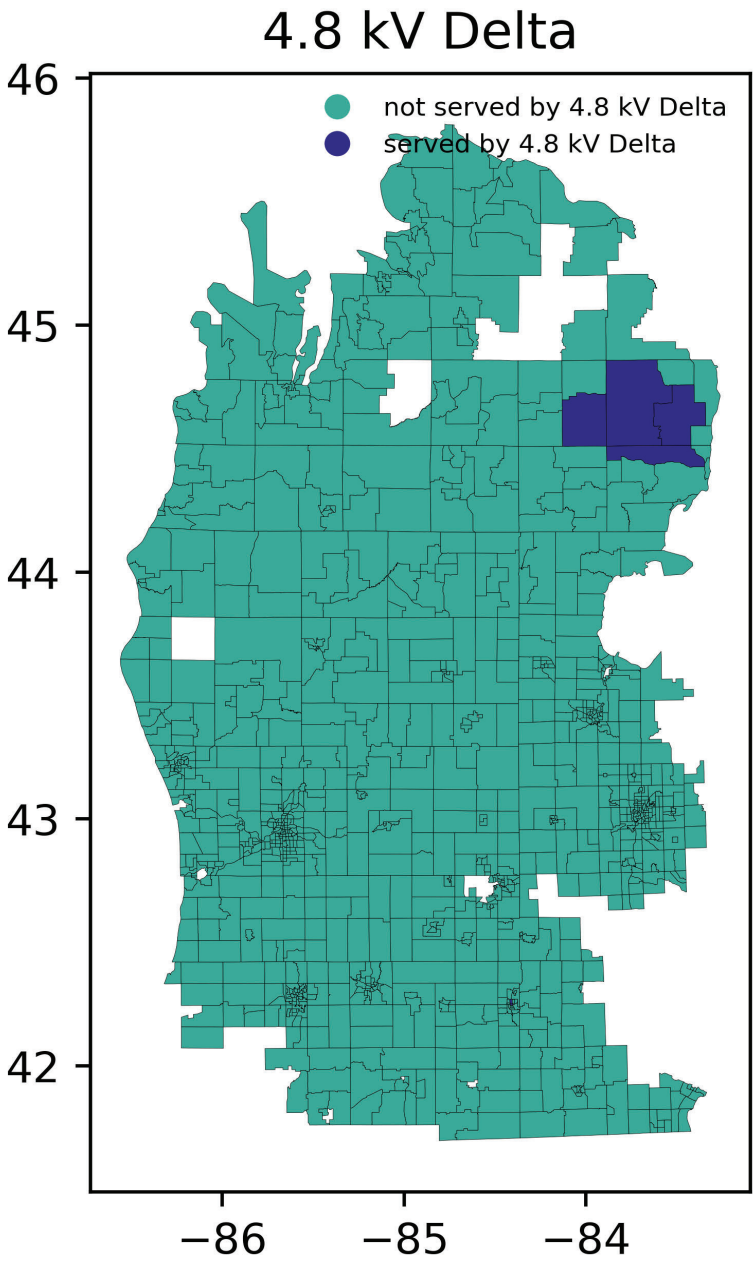


Figure B5. Map of 2010 census tracts in Consumers service territory served by 4.8 kV Delta feeders.

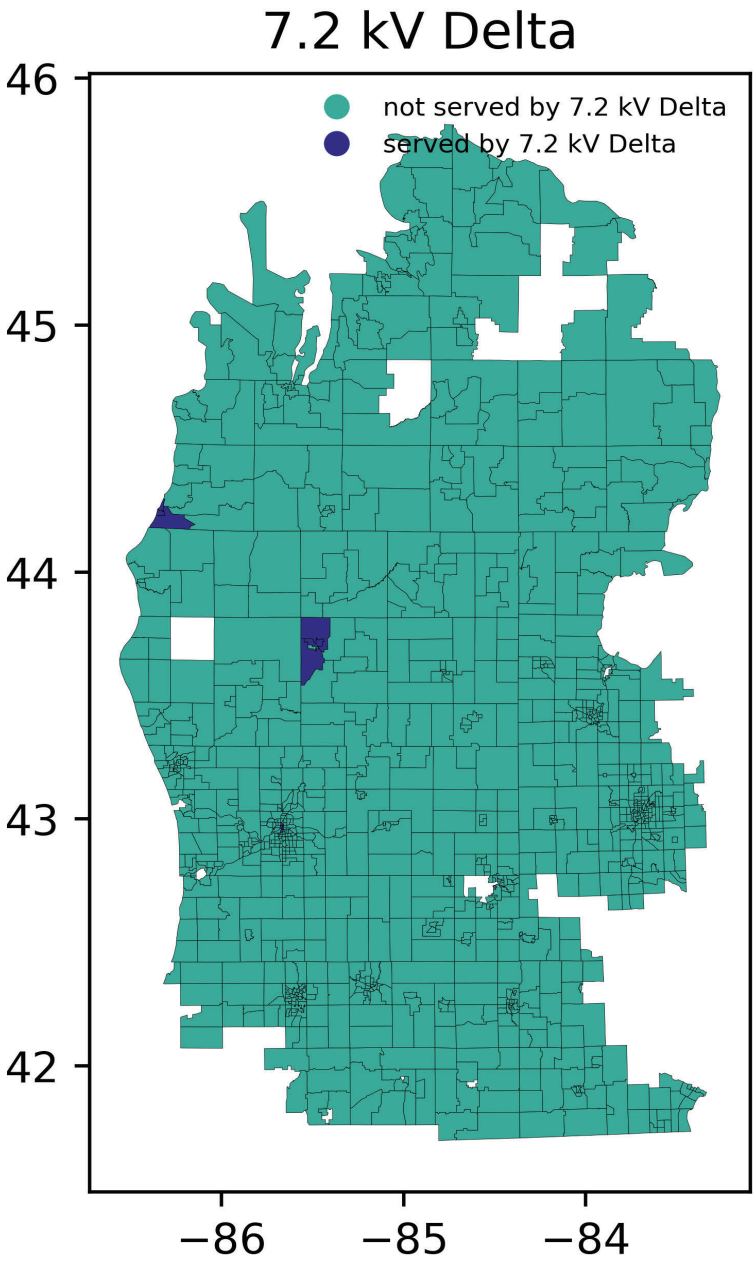


Figure B6. Map of 2010 census tracts in Consumers service territory served by 7.2 kV Delta feeders.

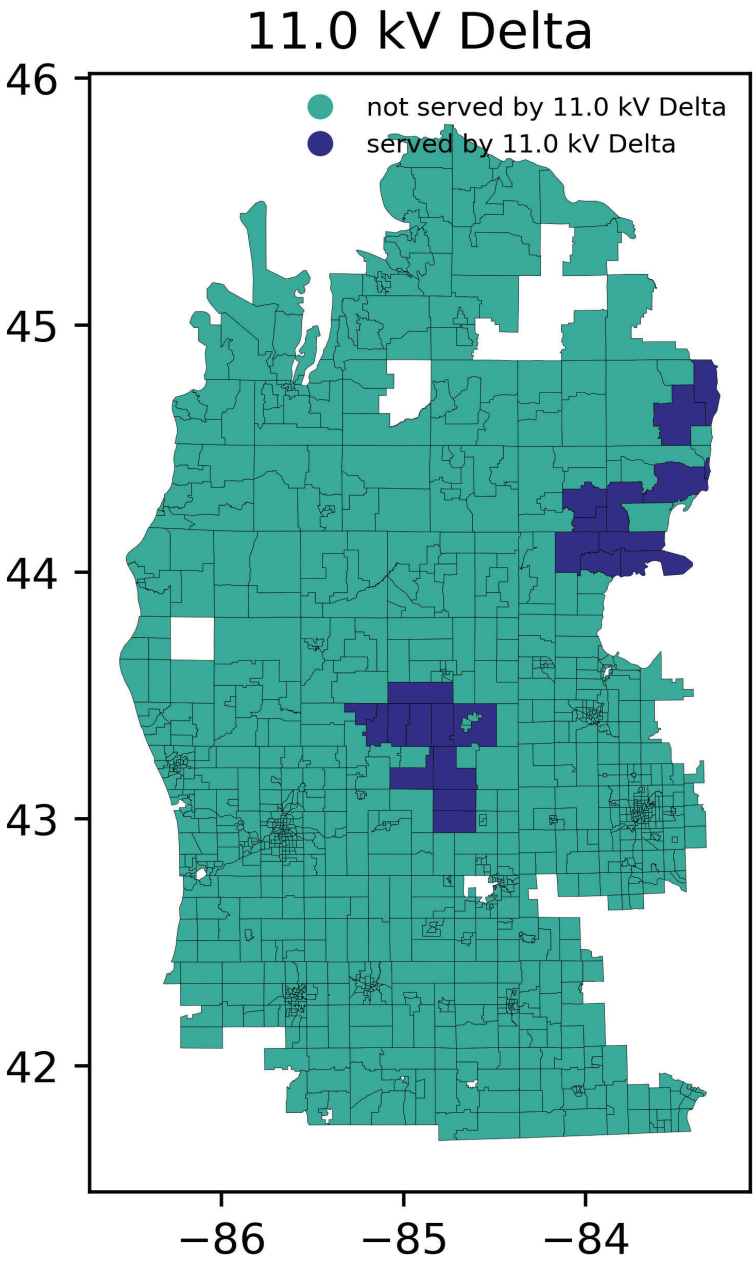


Figure B7. Map of 2010 census tracts in Consumers service territory served by 11.0 kV Delta feeders.

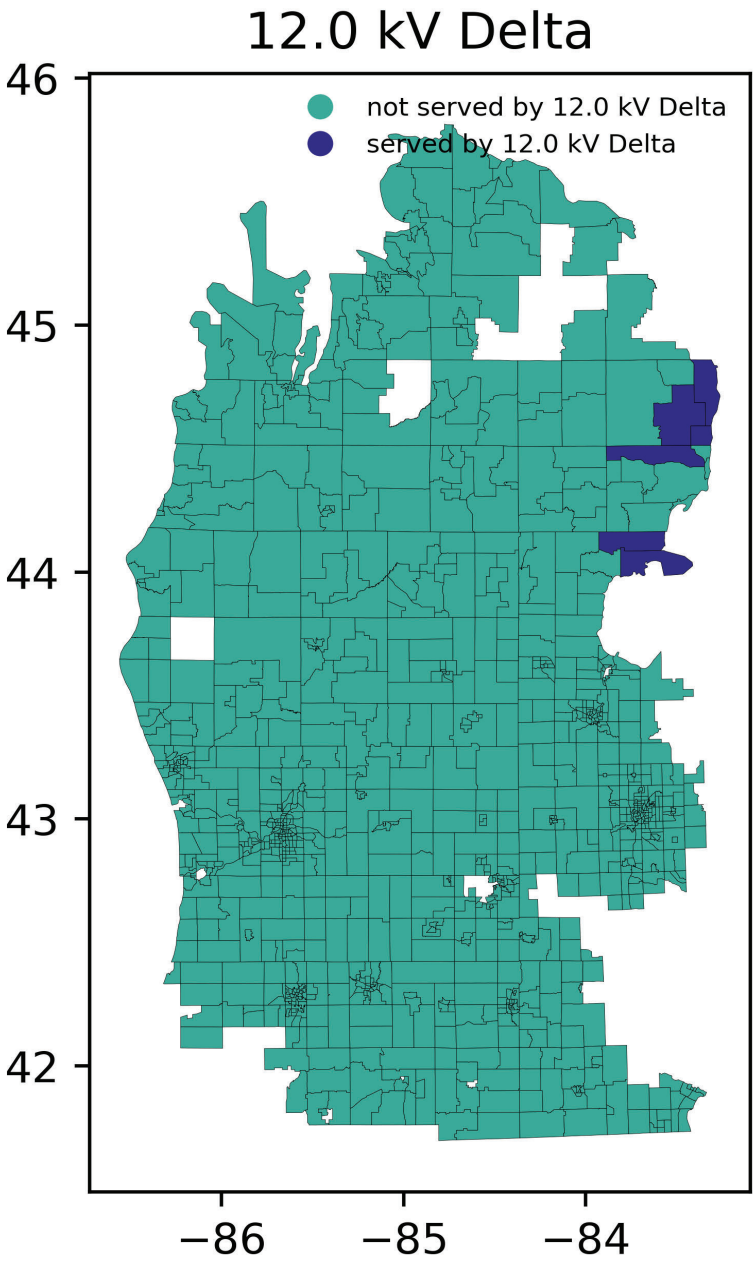


Figure B8. Map of 2010 census tracts in Consumers service territory served by 12.0 kV Delta feeders.

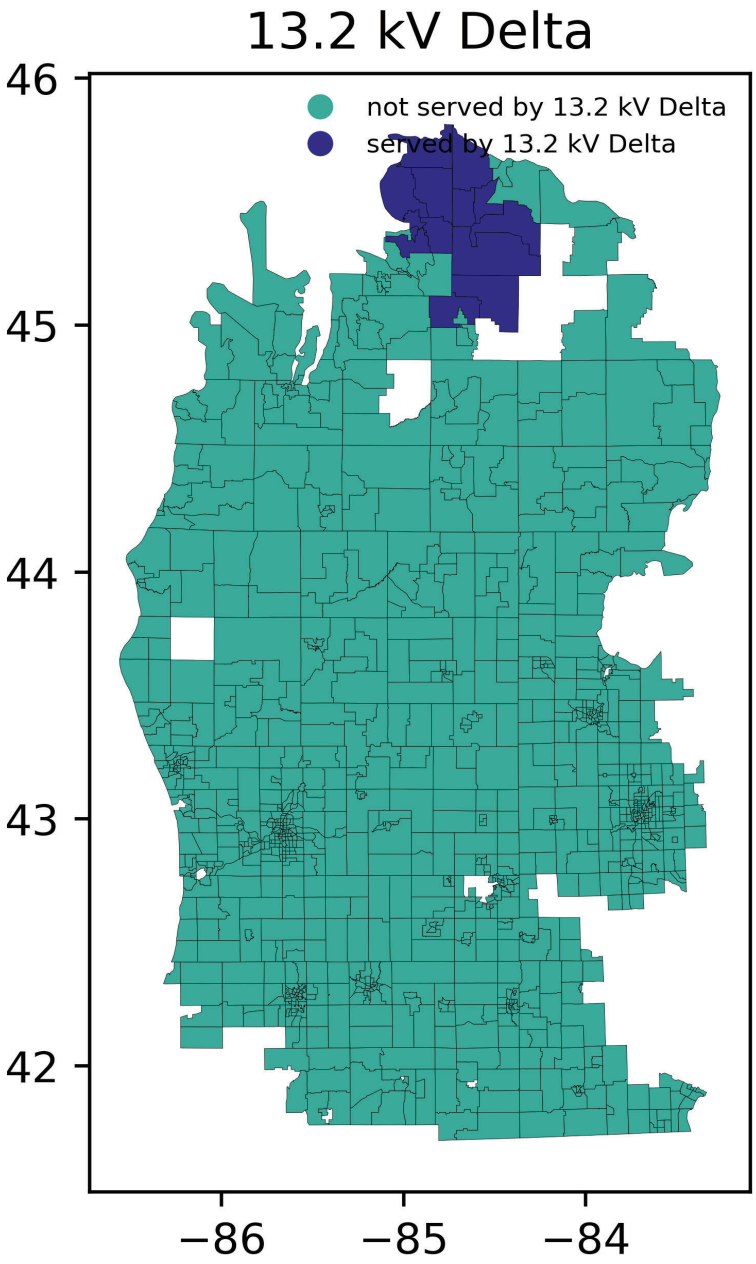


Figure B9. Map of 2010 census tracts in Consumers service territory served by 13.2 kV Delta feeders.

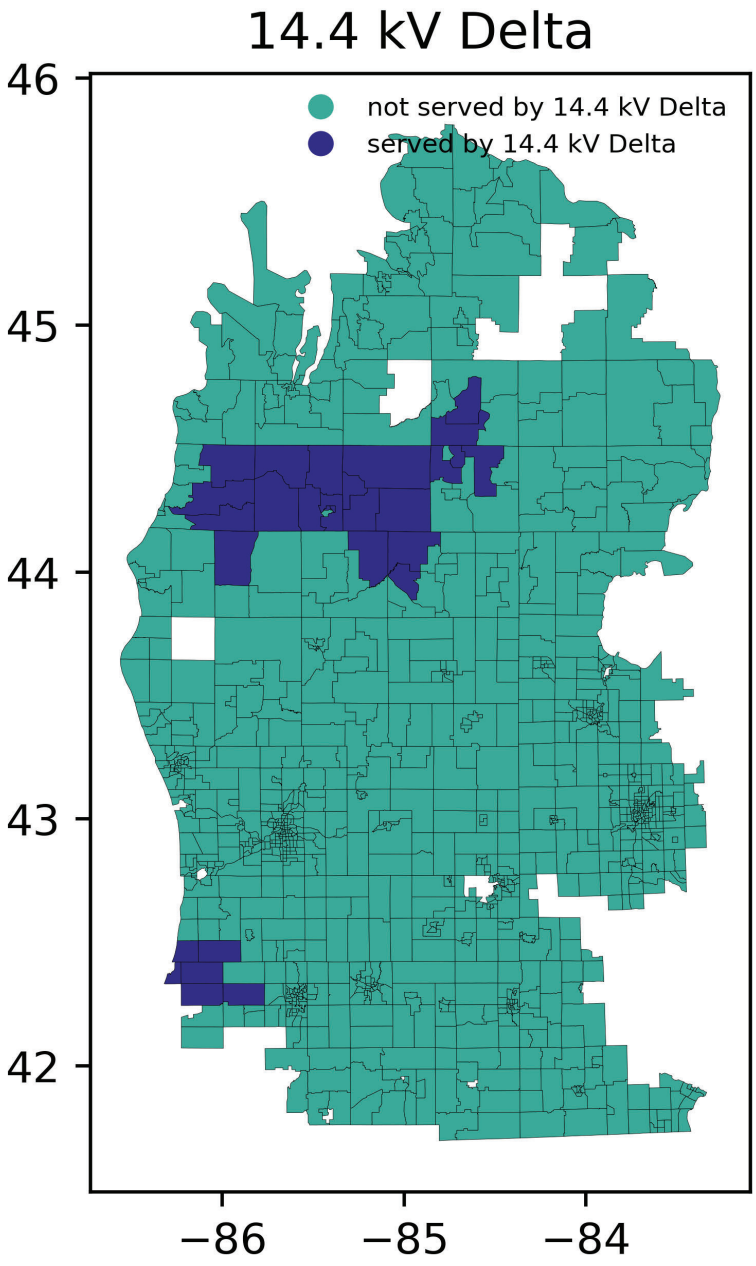


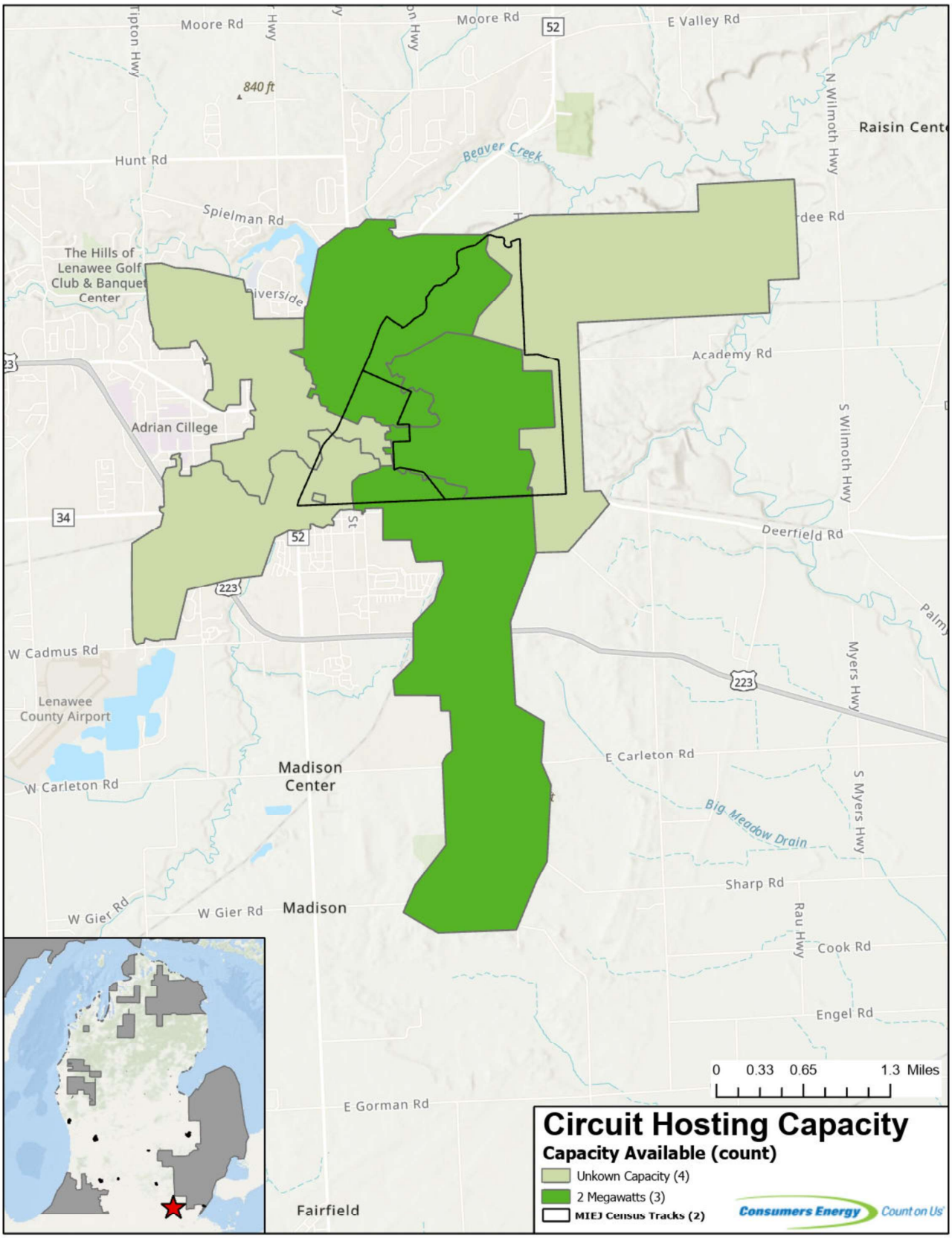
Figure B10. Map of 2010 census tracts in Consumers service territory served by 14.4 kV Delta feeders.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
AMI Opt Out Charges
Electric Distribution

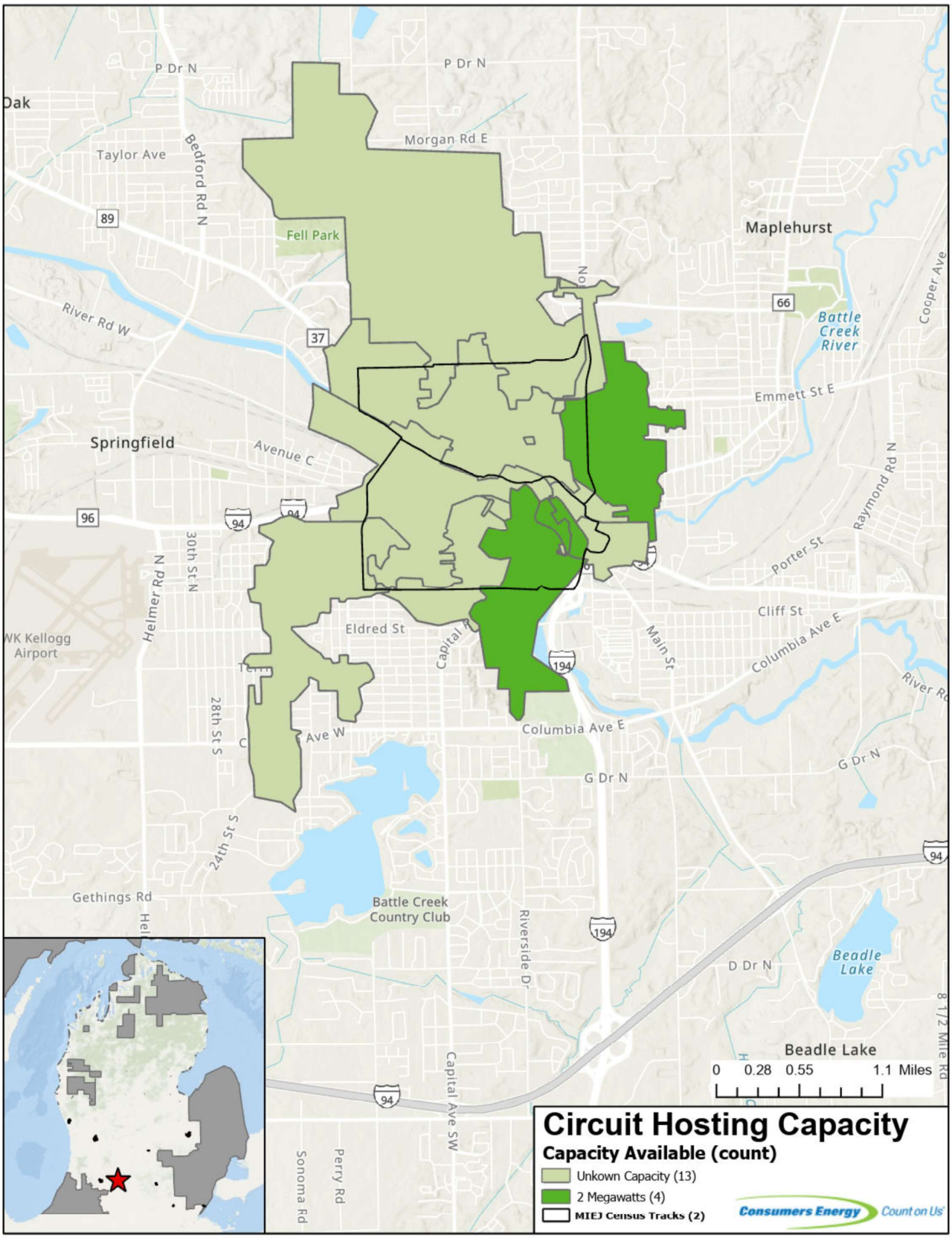
Case No.: U-21870
Exhibit No.: A-136 (MPK-26)
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No.	(a) Description	(b) Charge per Meter
	Up-Front Costs:	
1	*Customer requests to replace an existing smart meter with legacy meter*	
2	Replace Existing Smart Meter with Legacy Meter	45.40
3	Smart Meter Deployment Exceptions Process - Systems Cost	2.63
4	Customer Support	3.44
5	Restore Premise to Standard metering	93.57
6	Turn on/off	71.18
7	**One Time Cost**	**216.22**
8	*Ongoing Costs*	
9	Meter Reading	0.29
10	Meter Testing Program for Legacy Meters	0.08
11	Re read orders	3.51
12	Monitoring, Tracking and correcting accounts	1.29
13	Non-communicating Meter Retention	0.03
14	Meter Reader Handheld Device Purchases	0.27
15	Net of ongoing AMI capital and ongoing maintenance costs	(2.38)
16	**Monthly Ongoing Cost**	**3.09**

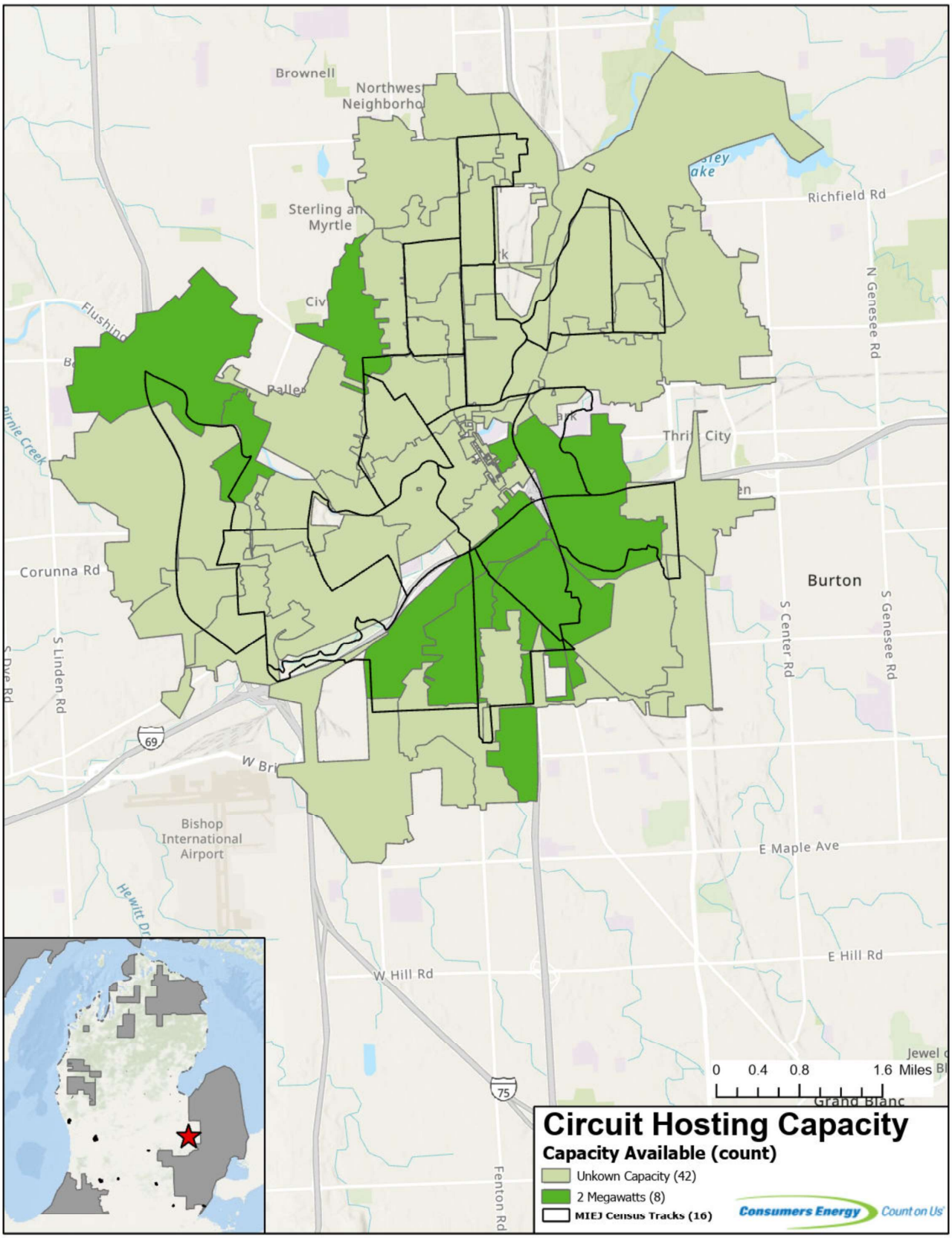
Adrian Metro Area



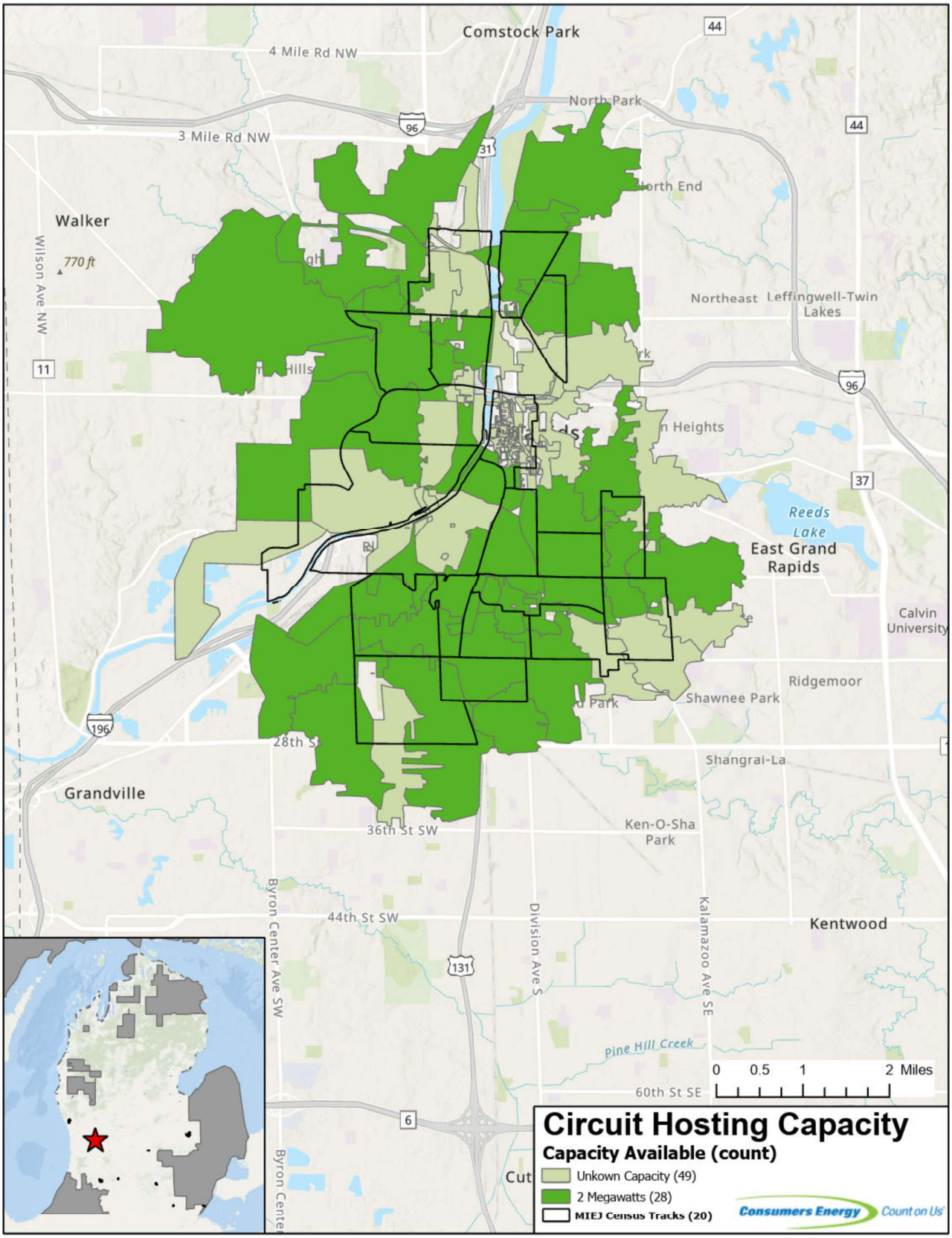
Battle Creek Metro Area



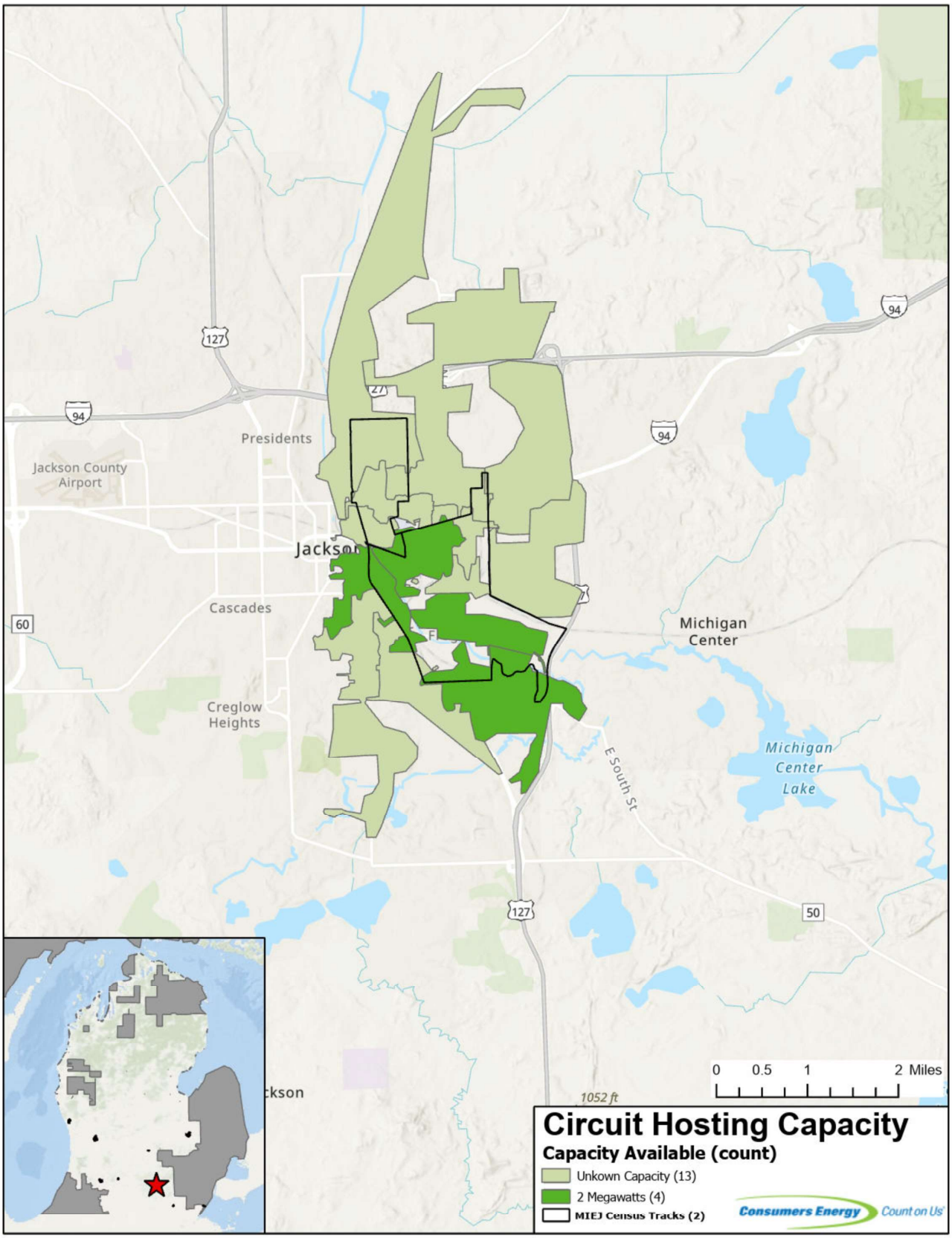
Flint Metro Area



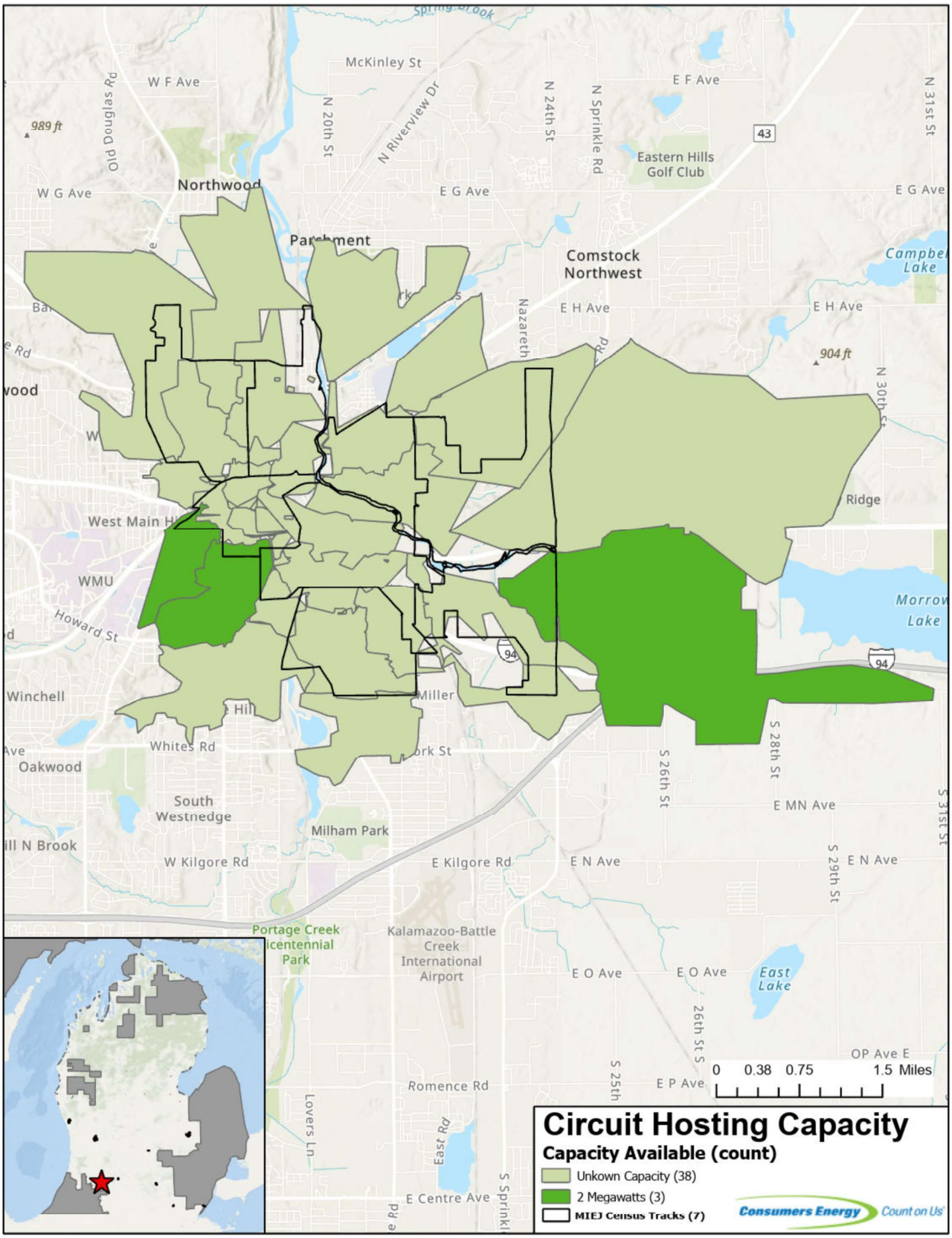
Grand Rapids Metro Area



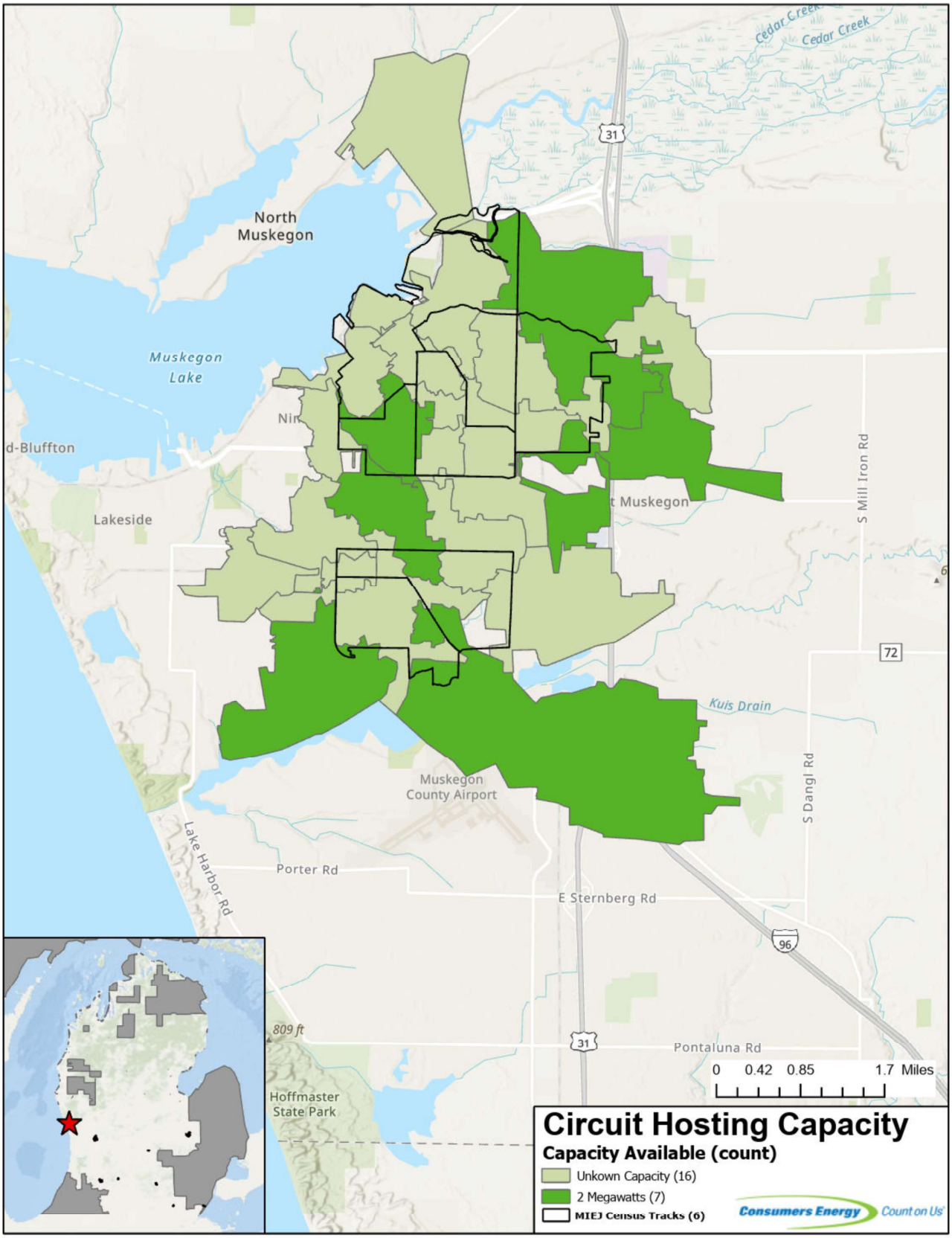
Jackson Metro Area



Kalamazoo Metro Area



Muskegon Metro Area



Exponent®

Reliability and Disconnections Regression Analysis

Overview and Observations

Gitanjali Bhattacharjee, PhD
Ezra Jampole, PhD

June 2, 2025

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Executive Summary

Reliability and Disconnections Regression Analysis

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Background

- March 2024 MPSC Order directed Consumers to use regression analysis to assess whether customers in Environmental Justice (EJ) communities experience lower levels of distribution reliability than customers in other communities.
- March 2025 MPSC Order directed Consumers to include residential involuntary disconnections for non-payment in the regression analysis.

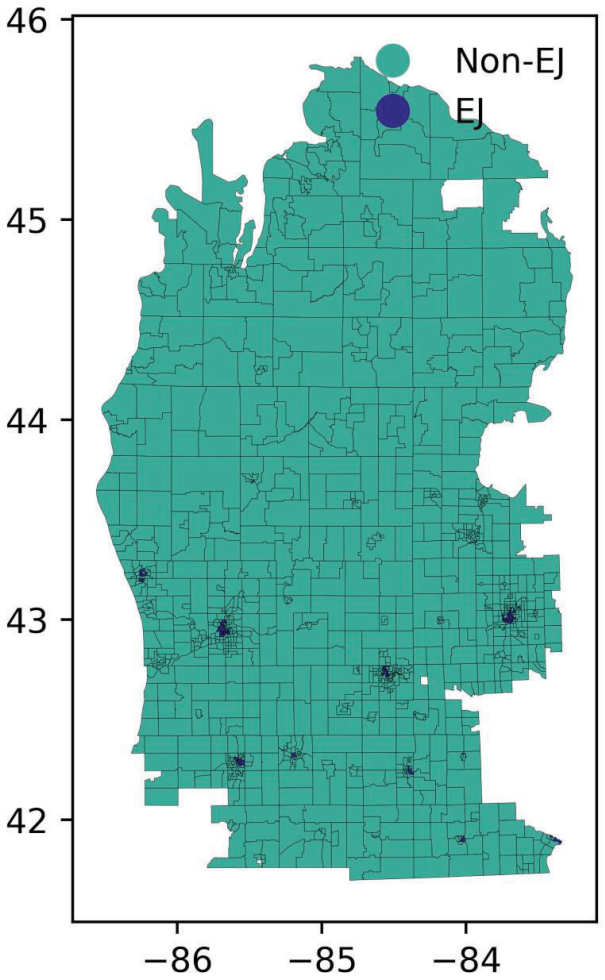
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EJ Communities

- EJ and Non-EJ census tracts
  - EJ if MiEJScreen Overall Score > 80; and
  - Non-EJ otherwise.

Categories	Environmental Exposure	Environmental Effects	Sensitive Populations	Socioeconomic Factors
Indicators	NATA Air Toxics Cancer Risk NATA Respiratory Hazard Index NATA Diesel Particulate Matter Particulate Matter ($PM_{2.5}$) Ozone Traffic Density	Proximity to Cleanup Sites Proximity to Hazardous Waste Facilities Impaired Water Bodies Proximity to Solid waste Sites and Facilities Lead Paint Indicator Proximity to RMP Sites Wastewater Discharge Indicator	Asthma Cardiovascular Disease Low Birth Weight Infants Blood Lead Level Life Expectancy	Low Income Population Black, Indigenous, People of Color Population Educational Attainment Linguistic Isolation Population Under Age 5 Population Over Age 64 Unemployment Housing Burden
Sub Scores	**Environmental Conditions** (Average percentile of Environmental Exposure indicators + 0.5 x average percentile of Environmental Effects indicators) / 1.5		**Population Characteristics** (Average percentile of Sensitive Population indicators + average percentile of Socioeconomic Factor indicators) / 2	
Score	**Final Composite Score = Environmental Conditions score x Population Characteristics score** **MiEJScreen Score**			

Source: Office of the Environmental Justice Public Advocate and Michigan Department of Environment, Great Lakes, and Energy. (2024). MiEJScreen1.0: Michigan Environmental Justice Mapping and Screening Tool Technical Report.



EJ and non-EJ communities within Consumers' service territory.

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Reliability and disconnections regression analysis: Scope

Reliability

- Are there statistically significant differences in the average reliability of different groups of customers?
- What correlations exist between communities' demographic characteristics and their reliability?
- What correlations exist between circuit characteristics and their reliability?

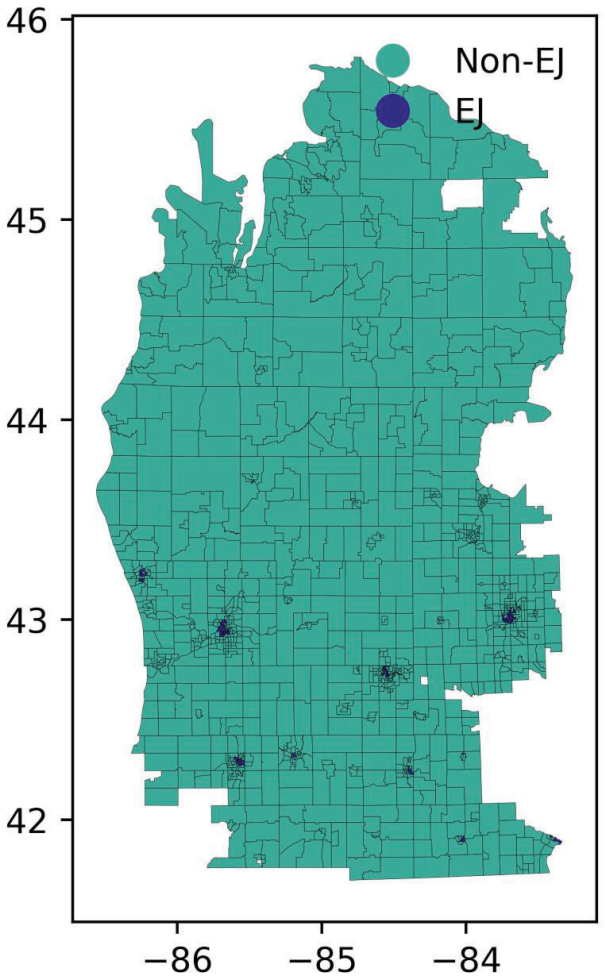
Disconnections

- What correlations exist between communities' demographic characteristics and rates of residential involuntary disconnections for non-payment?
- Do customers with the worst reliability also experience higher rates of disconnections than other customers?

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Groups of customers

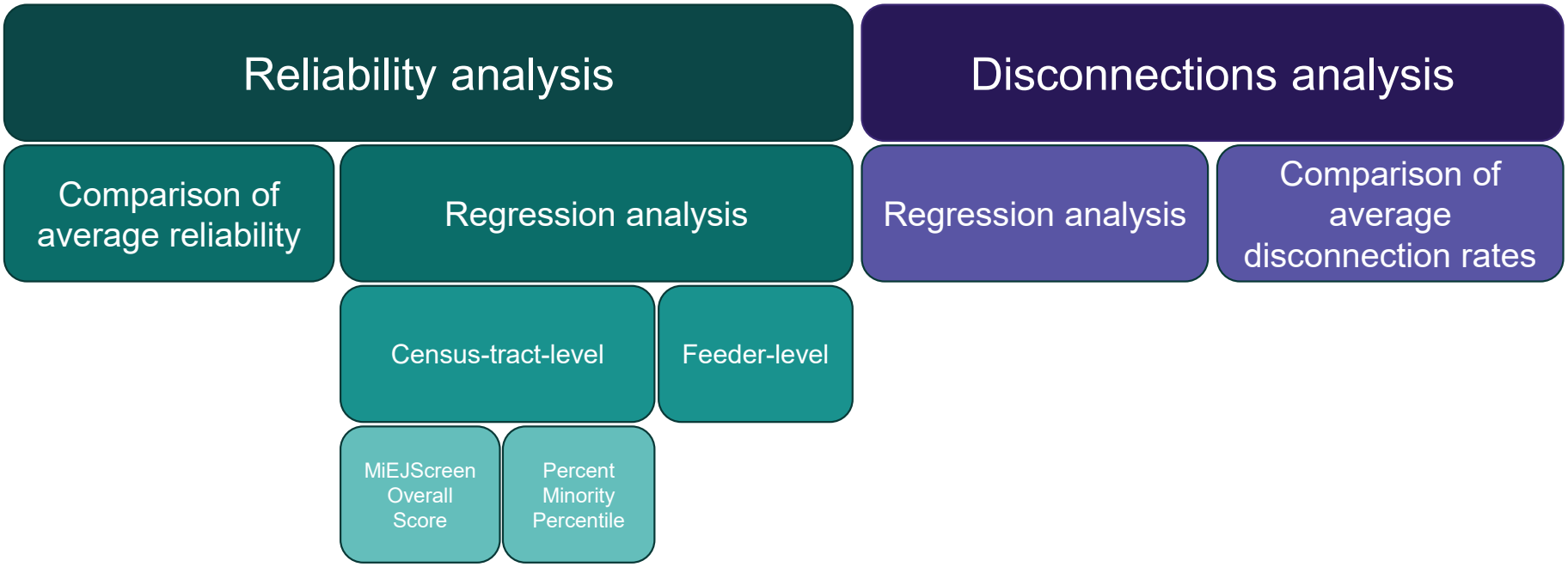
- EJ and Non-EJ census tracts
- Urban and Rural census tracts
- Low-Income and High-Income census tracts
- High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts



EJ and non-EJ communities within Consumers' service territory.

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Analysis Roadmap



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Summary of observations: Reliability

Reliability

- Are there statistically significant differences in the average reliability of different groups of customers?
- What correlations exist between communities' demographic characteristics and their reliability?
- What correlations exist between circuit characteristics and their reliability?

When there are statistically significant differences in average reliability, EJ census tracts tend to have better average reliability than Non-EJ census tracts.

Increasing MiEJScreen Overall Score and increasing Percent Minority Percentile are often associated with improving reliability.

Feeders that serve EJ census tracts tend to have more frequent outages than feeders that don't serve EJ census tracts.

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Summary of observations: Disconnections

Disconnections

- What correlations exist between communities' demographic characteristics and rates of residential involuntary disconnections for non-payment?
- Do customers with the worst reliability also experience higher rates of disconnections than other customers?

When all other variables are held constant, increasing Percentage Minority Population in a census tract is statistically significant and associated with increasing disconnection rate.

Percentage Below Poverty, Population Density, Median Home Value, Percentage of Homes Built After 1990, and Percentage Renters also have statistically significant correlations with disconnection rate.

No; the census tracts with the worst reliability tend to have lower average disconnection rates than the rest of the census tracts.

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Agenda



1. Executive Summary
2. Regression analysis results: Reliability
3. Regression analysis results: Disconnections
4. Key Takeaways
5. Next Steps

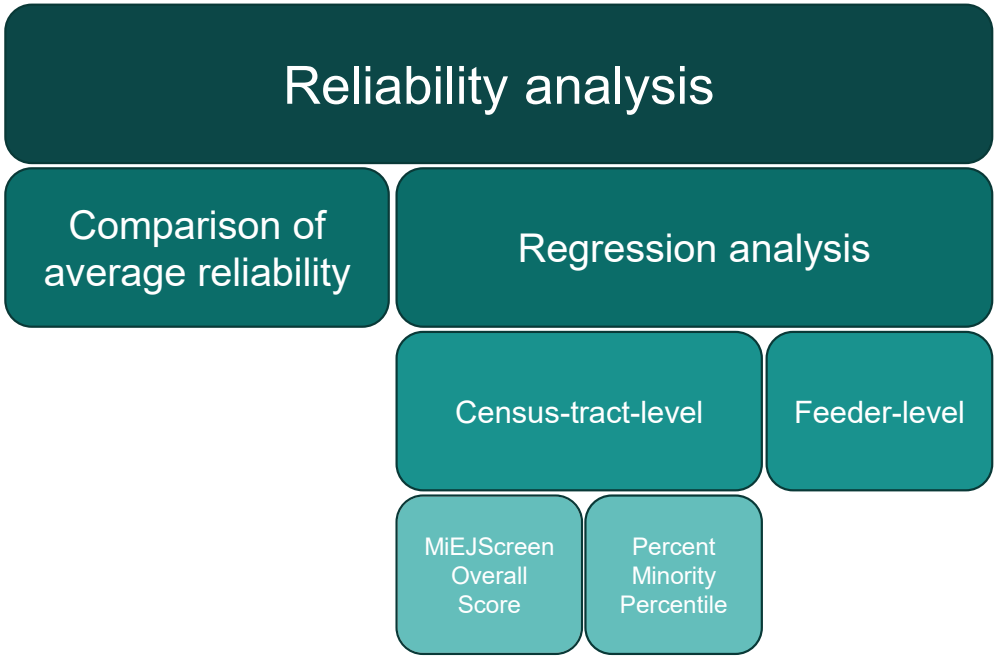
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2. Regression analysis results: Reliability

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2. Reliability regression analysis: Scope

1. Are there statistically significant differences in the average reliability of different groups of customers?
2. What correlations exist between demographic characteristics of census tracts and their reliability?
3. What correlations exist between feeder characteristics – including the demographic characteristics of the communities they serve – and their reliability?



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2.1 Comparison of average reliability

1. Are there statistically significant differences in the average reliability of different groups of customers?
   - Used binary difference-in-means t-test to compare average reliability (by 18 different metrics).

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2.1 Comparison of average reliability: EJ and Non-EJ

When there are statistically significant differences in the mean reliability of EJ and non-EJ census tracts, EJ census tracts consistently experience better average reliability.

Excerpt of Table 5.

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.13E+03	8.90E+02	2.37E+02	6.62E-03	TRUE	EJ
	2021	1.23E+03	8.19E+02	4.14E+02	5.55E-07	TRUE	EJ
	2022	1.12E+03	8.52E+02	2.64E+02	2.86E-03	TRUE	EJ
	2023	1.16E+03	8.10E+02	3.52E+02	6.20E-05	TRUE	EJ
	2024	1.10E+03	7.97E+02	3.08E+02	2.97E-04	TRUE	EJ
Total Customer Interruptions	2020	2.39E+03	1.82E+03	5.72E+02	1.33E-02	TRUE	EJ
	2021	2.91E+03	1.39E+03	1.52E+03	5.83E-16	TRUE	EJ
	2022	2.31E+03	1.77E+03	5.42E+02	5.06E-02	FALSE	N/A
	2023	2.50E+03	1.56E+03	9.40E+02	3.44E-04	TRUE	EJ
	2024	2.44E+03	1.43E+03	1.01E+03	1.56E-06	TRUE	EJ
SAIDI including MEDs	2020	5.24E+02	2.85E+02	2.39E+02	5.69E-05	TRUE	EJ
	2021	9.66E+02	3.06E+02	6.60E+02	3.74E-28	TRUE	EJ
	2022	4.56E+02	2.90E+02	1.66E+02	1.49E-04	TRUE	EJ
	2023	9.36E+02	4.76E+02	4.60E+02	2.50E-05	TRUE	EJ
	2024	4.90E+02	2.89E+02	2.00E+02	1.40E-05	TRUE	EJ
SAIDI excluding MEDs	2020	1.99E+02	1.38E+02	6.08E+01	5.05E-05	TRUE	EJ
	2021	2.45E+02	1.34E+02	1.11E+02	3.55E-07	TRUE	EJ
	2022	1.84E+02	1.28E+02	5.60E+01	2.02E-04	TRUE	EJ
	2023	1.84E+02	1.10E+02	7.36E+01	6.37E-10	TRUE	EJ
	2024	1.64E+02	1.06E+02	5.85E+01	5.07E-05	TRUE	EJ
SAIFI including MEDs	2020	1.33E+00	1.16E+00	1.75E-01	1.01E-01	FALSE	N/A
	2021	1.65E+00	1.05E+00	5.98E-01	2.69E-08	TRUE	EJ
	2022	1.27E+00	1.20E+00	7.19E-02	6.35E-01	FALSE	N/A
	2023	1.40E+00	1.04E+00	3.57E-01	5.60E-03	TRUE	EJ
	2024	1.33E+00	9.16E-01	4.14E-01	1.27E-04	TRUE	EJ

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2.1 Comparison of average reliability: Urban and Rural

When there are statistically significant differences in the mean reliability of Urban and Rural census tracts, Urban census tracts consistently experience better average reliability.

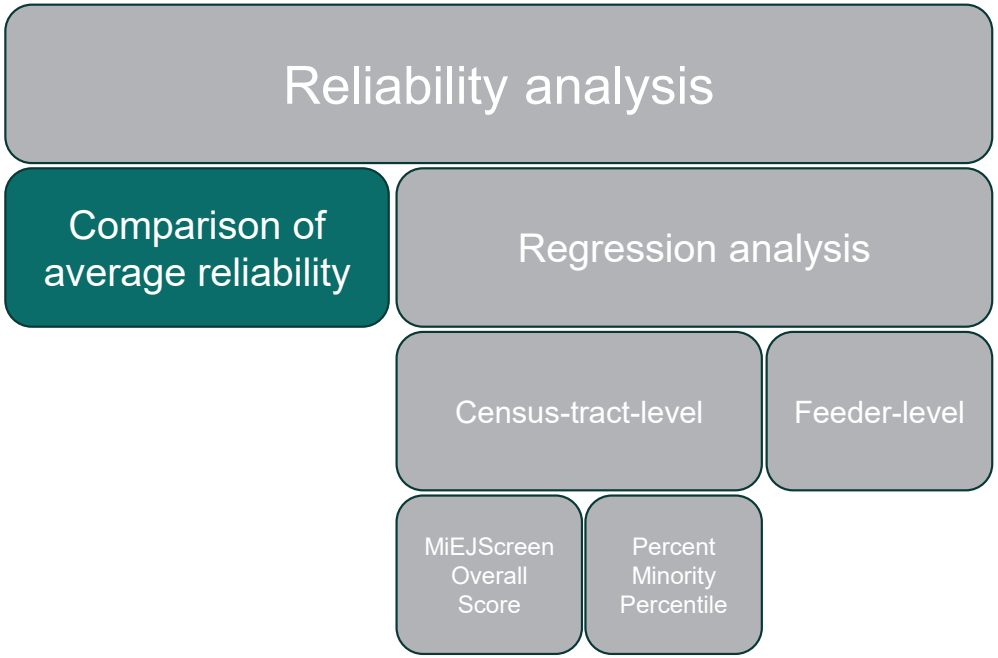
Excerpt of Table 6.

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
CEMI-7	2020	2.01E-02	1.39E-03	1.87E-02	2.46E-11	TRUE	Urban
	2021	3.20E-02	3.54E-03	2.84E-02	1.04E-13	TRUE	Urban
	2022	1.51E-02	3.03E-03	1.21E-02	5.86E-08	TRUE	Urban
	2023	2.52E-02	2.49E-03	2.27E-02	3.04E-13	TRUE	Urban
	2024	2.96E-02	4.40E-03	2.52E-02	4.74E-12	TRUE	Urban
CEMI-10	2020	4.83E-03	5.11E-05	4.78E-03	9.64E-03	TRUE	Urban
	2021	3.68E-03	3.39E-06	3.67E-03	4.79E-07	TRUE	Urban
	2022	2.37E-03	1.39E-05	2.36E-03	4.79E-03	TRUE	Urban
	2023	3.84E-03	2.25E-05	3.81E-03	1.03E-05	TRUE	Urban
	2024	6.01E-03	2.57E-03	3.44E-03	1.39E-01	FALSE	N/A
CELID-5	2020	3.42E-01	1.77E-01	1.65E-01	4.14E-26	TRUE	Urban
	2021	5.11E-01	2.35E-01	2.76E-01	4.80E-58	TRUE	Urban
	2022	3.33E-01	1.94E-01	1.39E-01	8.27E-21	TRUE	Urban
	2023	3.98E-01	2.89E-01	1.09E-01	2.36E-08	TRUE	Urban
	2024	3.58E-01	2.11E-01	1.47E-01	6.75E-19	TRUE	Urban
CELID-24	2020	1.06E-01	4.51E-02	6.07E-02	7.02E-11	TRUE	Urban
	2021	2.39E-01	5.33E-02	1.85E-01	5.01E-52	TRUE	Urban
	2022	8.23E-02	3.06E-02	5.18E-02	2.57E-15	TRUE	Urban
	2023	1.92E-01	1.27E-01	6.53E-02	4.35E-05	TRUE	Urban
	2024	9.03E-02	4.50E-02	4.53E-02	2.25E-07	TRUE	Urban
Percent of all-weather restorations made within 36 hours	2020	9.70E-01	9.69E-01	1.73E-03	7.47E-01	FALSE	N/A
	2021	9.28E-01	9.68E-01	-4.04E-02	5.62E-13	TRUE	Urban
	2022	9.71E-01	9.89E-01	-1.75E-02	2.09E-06	TRUE	Urban
	2023	9.32E-01	9.32E-01	-2.32E-05	9.98E-01	FALSE	N/A
	2024	9.77E-01	9.79E-01	-1.53E-03	7.26E-01	FALSE	N/A

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2.1 Comparison of average reliability: Summary

1. Are there statistically significant differences in the average reliability of different groups of customers?
   - Yes: EJ census tracts tend to have **better** average reliability than Non-EJ census tracts.
   - Yes: Urban, Low-Income, and High-Percent-Minority-Percentile tend to have **better** average reliability than Rural, High-Income, and Low-Percent-Minority-Percentile census tracts.



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2.2 Census-tract-level reliability regression: Overview

2. What correlations exist between demographic characteristics of census tracts and their reliability?
   - Built regression models to relate reliability to census-tract-level demographic characteristics.

Average Values

Excerpt of Table 3. The average value (over all 1050 of the 2010 census tracts in Consumers' service territory for which reliability data was provided) of four census-tract-level reliability metrics in each year from 2020 through 2024.

Reliability Metric	2020	2021	2022	2023	2024
SAIDI excluding MEDs	195.52	239.23	181.27	179.70	160.90

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2.2 Regression results with MiEJScreen Overall Score: SAIDI excluding MEDs

When all other variables are held constant:

- A one percentage point increase in the **MiEJScreen Overall Score** is associated with a 1.36 minute decrease in SAIDI excluding MEDs (improving reliability);
- A one percentage point increase in **Poverty** is associated with a 0.4 minute increase in SAIDI excluding MEDs (worsening reliability);
- An increase in **Population Density** of 100 people per square mile is associated with a 0.9 minute decrease in SAIDI excluding MEDs (improving reliability);
- A one percentage point increase in **Percent Unemployed** is associated with an approximately 3 minute increase in SAIDI excluding MEDs (worsening reliability); and
- A one percentage point increase in **Housing Burden** is associated with a 0.4 minute decrease in SAIDI excluding MEDs (improving reliability).

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2.2 Census-tract-level reliability regression: Summary for MiEJScreen Overall Score

- **These results show no evidence that census tracts with higher MiEJScreen Overall Scores tend to have worse reliability than other census tracts.**
- MiEJScreen Overall Score is statistically significant and correlated with improving reliability in terms of:
  - Unique Customers with an Interruption;
  - Total Customer Interruptions;
  - SAIDI (excluding and including MEDs);
  - SAIFI (excluding and including MEDs);
  - CAIDI (excluding and including MEDs);
  - CELID-5 and -24;
  - CEMI-4, -5, and -7; and
  - the percentage of all-weather restorations made within 36 hours.

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2.2 Regression results with Percent Minority Percentile: SAIDI excluding MEDs

When all other variables are held constant:

- A one percentage point increase in the **Percent Minority Percentile** is associated with a 1 minute decrease in SAIDI excluding MEDs (improving reliability);
- A one percentage point increase in **Poverty** is associated with a 0.8 minute increase in SAIDI excluding MEDs (worsening reliability);
- An increase in **Population Density** of 100 people per square mile is associated with a 1 minute decrease in SAIDI excluding MEDs (improving reliability);
- A one percentage point increase in **Percent Unemployed** is associated with a 3.1 minute increase in SAIDI excluding MEDs (worsening reliability); and
- A one percentage point increase in **Housing Burden** is associated with a 0.4 minute decrease in SAIDI excluding MEDs (improving reliability).

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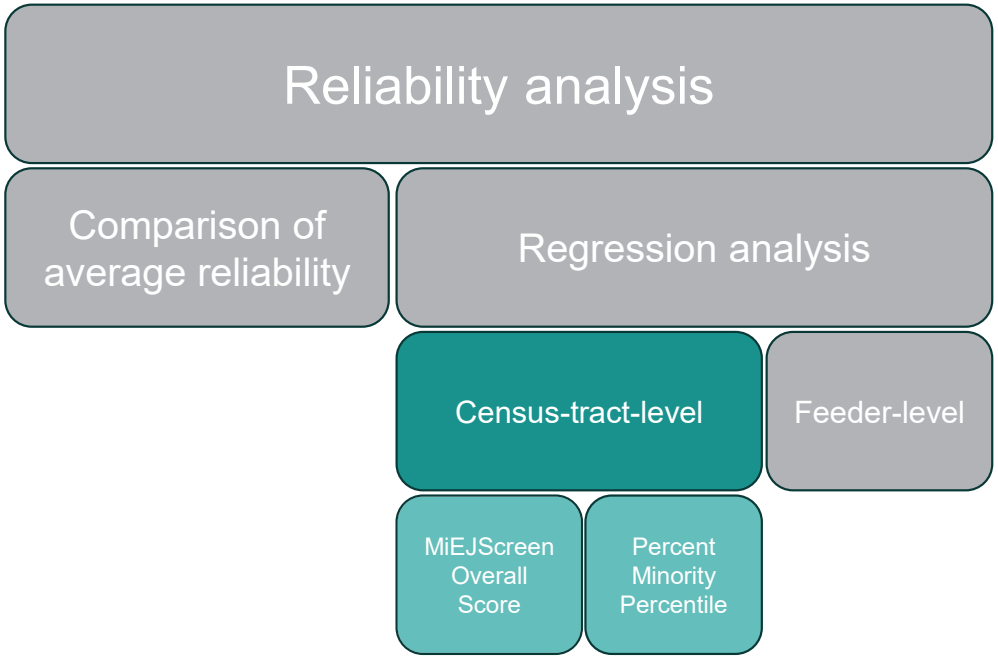
2.2 Census-tract-level reliability regression: Summary for Percent Minority Percentile

- **These results show no evidence that census tracts with higher Percent Minority Percentile values tend to have worse reliability than other census tracts.**
- Percent Minority Percentile is statistically significant and correlated with improving reliability in terms of:
  - Unique Customers with an Interruption;
  - Total Customer Interruptions;
  - SAIDI (excluding and including MEDs);
  - SAIFI (excluding and including MEDs);
  - CELID-5 and -24; and
  - CEMI-4, -5, and -7.

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2.2 Census-tract-level reliability regression: Summary

2. What correlations exist between demographic characteristics of census tracts and their reliability?
   - Increasing MiEJScreen Overall Score tends to be associated with improving reliability, when a statistically significant correlation between the two exists.
   - Increasing Percent Minority Percentile also tends to be associated with improving reliability.
   - Census tracts with higher poverty and unemployment rates tend to have longer and more frequent outages when all other variables are held constant.



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2.3 Feeder-level reliability regression: Overview

3. What correlations exist between feeder characteristics and their reliability?
   - Built regression models to relate reliability to feeder characteristics.
     - **Data**: For each feeder:
       - 4 reliability metrics (2020-2024):
         - SAIDI (excluding and including MEDs)
         - SAIFI (excluding and including MEDs)
       - Physical attributes
       - Percent of its length within a 2010 census tract
       - Demographic variables based on data from MiEJScreen

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2.3 Feeder-level reliability regression: Feeder characteristics

Physical characteristics of feeders that were included in the models are:

- Customers per Primary Line Mile;
- Mean Canopy Cover Percentage;
- Open Wire Secondary Miles;
- Primary Miles;
- Primary Underground Percentage;
- Voltage (categorical); and
  - Reference value is 4.8/8.32 kV Wye Grounded, since it's the most common of all feeder voltages.
- Years Since Last Trim < 7 (binary).

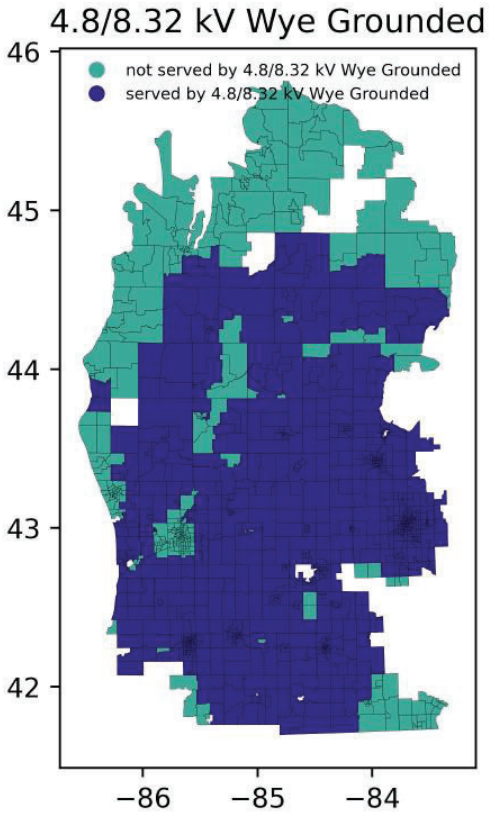


Figure B1. Map of 2010 census tracts in Consumers service territory served by 4.8/8.32 kV Wye Grounded feeders.

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2.3 Feeder-level reliability regression: Feeder characteristics

We also included demographic characteristics of the areas served by each feeder as binary variables:

- Serves an EJ census tract;
- Serves an Urban census tract;
- Serves a Low-Income census tract; and
- Serves a High-Percent-Minority-Percentile census tract.

A feeder was considered as serving a type of census tract if any part of its length overlapped with that type of census tract.

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2.3 Feeder-level regression results: SAIDI excluding MEDs

- Voltage can have a large and statistically significant correlation with SAIDI excluding MEDs. When all other variables are held constant, the following Voltages have greater mean SAIDI excluding MEDs than the reference voltage:
  - 14.4/24.9 kV Wye Grounded (+72 minutes)
  - 4.8 kV Delta (+382 minutes)
  - 11.0 kV Delta
  - 12.0 kV Delta
  - 14.4 kV Delta
- All other feeder characteristics have statistically significant correlations with SAIDI excluding MEDs.
- Of the population characteristics included, only Serves Urban has a statistically significant correlation with SAIDI excluding MEDs (-22 minutes).

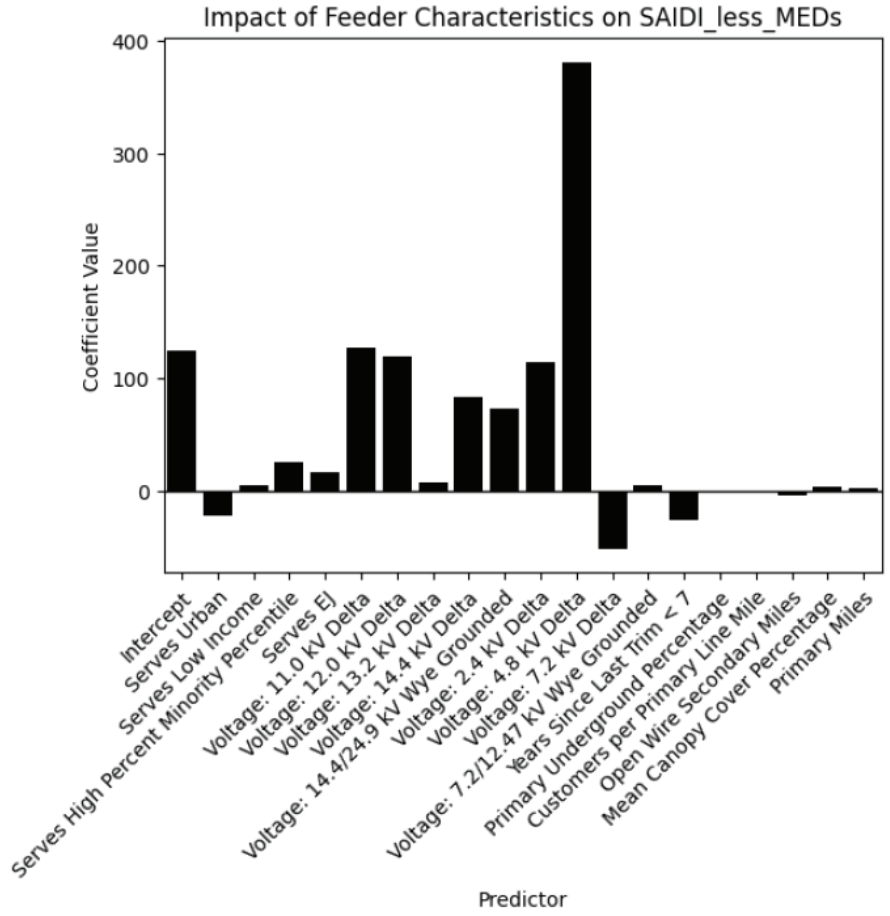


Figure 2. Regression coefficients for Model 6 (including feeder characteristics, population characteristics, and year fixed effects) of SAIDI excluding MEDs.

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2.3 Feeder-level regression results: SAIFI excluding MEDs

- Voltage can have a large and statistically significant correlation with SAIFI excluding MEDs. When all other variables are held constant and relative to the reference voltage:
  - 7.2/12.48 kV Wye Grounded (+0.1 interruptions/customer/year)
  - 14.4/24.9 kV Wye Grounded (+0.3 interruptions/customer/year)
  - 4.8 kV Delta (+1.1 interruptions/customer/year)
  - 11.0 kV Delta (+0.4 interruptions/customer/year)
  - 14.4 kV Delta (+0.6 interruptions/customer/year)
- All other feeder characteristics (except Customers per Primary Line Mile) have statistically significant correlations with SAIFI excluding MEDs.
- Of the population characteristics included, only Serves EJ has a statistically significant correlation with SAIFI excluding MEDs (+ 0.1 interruptions/customer/year).

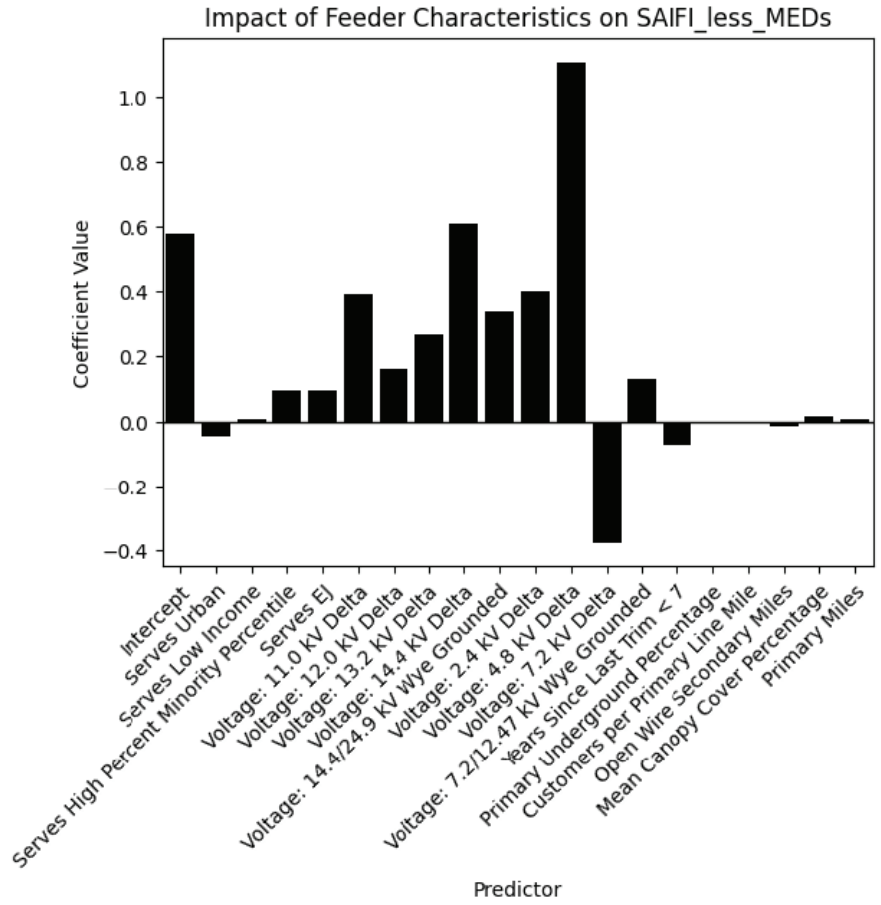
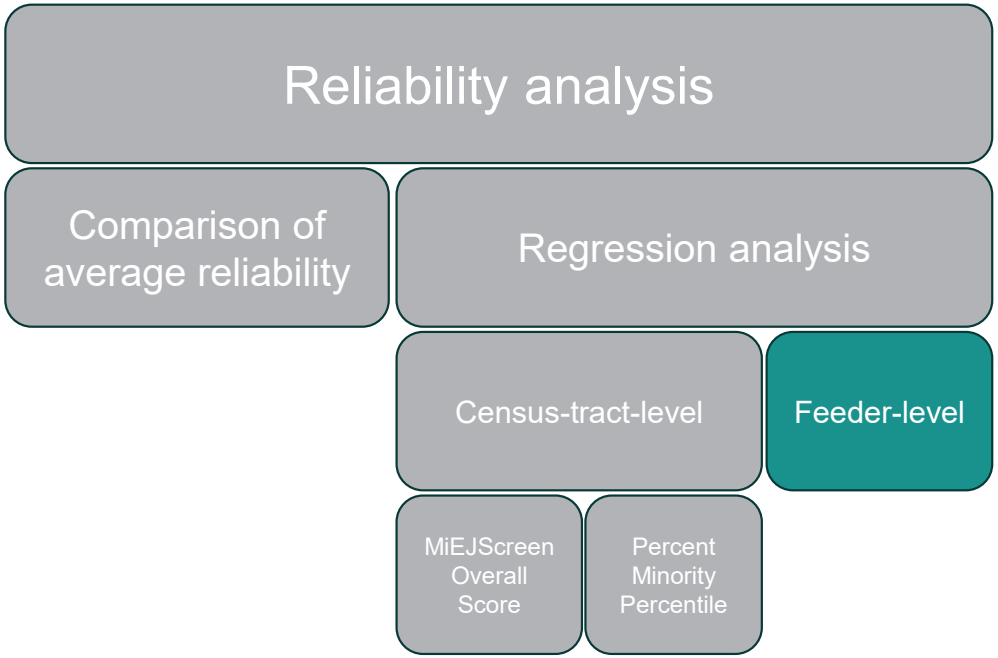


Figure 4. Regression coefficients for Model 6 (including feeder characteristics, population characteristics, and year fixed effects) of SAIFI excluding MEDs.

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2.3 Feeder-level reliability regression: Summary

3. What correlations exist between feeder characteristics and their reliability?
   - Feeders serving Urban census tracts tend to have shorter outages than those that do not serve Urban census tracts when all other variables are held constant.
     - Whether a feeder serves EJ, Low-Income, or High-Percent-Minority-Percentile census tracts was not found to have a statistically significant correlations with SAIDI.
   - Feeders serving EJ census tracts tend to have more frequent outages than feeders that don't serve EJ census tracts.
     - Whether a feeder serves Urban, Low-Income, or High-Percent-Minority-Percentile census tracts was not found to have statistically significant correlations with SAIFI.



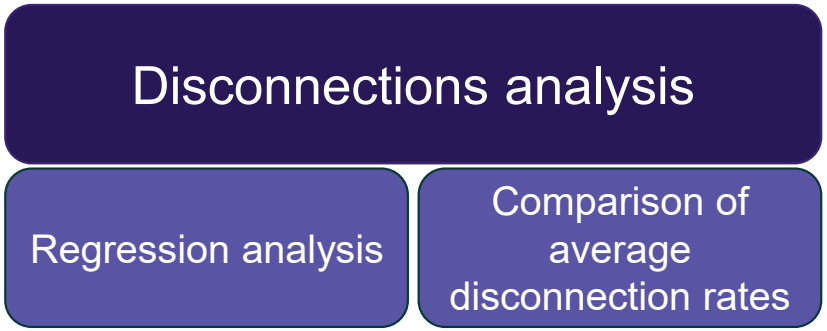
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3. Regression analysis results: Disconnections

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3. Disconnections analysis: Scope

1. What correlations exist between demographic characteristics (e.g., income, race/ethnicity) and disconnection rates?
2. Do communities with the worst reliability also have higher disconnection rates than other communities?



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3.1 Disconnections regression analysis: Overview

1. What correlations exist between demographic characteristics and disconnection rates?
   - Built regression models to relate disconnection rate to census-tract-level demographic characteristics.
     - **Data**: For each 2020 census tract in Consumers' service territory:
       - Count of disconnections in each year (2021*-2023)
       - Demographic variables based on data from the American Community Survey (ACS) – 5-year estimates (2021-2023**)

Table 18. The mean, standard deviation, minimum, and maximum disconnection rates (in units of disconnections per 1000 households) among census tracts in Consumers' service territory from 2020 through 2023.

Year	Mean	Standard Deviation	Minimum	Maximum
2020	14.85	11.54	0.40	80.62
2021	51.01	46.41	0.43	327.27
2022	49.33	44.90	0.37	279.87
2023	56.51	50.34	0.43	417.54

* Disconnection data for 2020 were excluded given the voluntary moratorium instituted by Consumers in response to the COVID-19 pandemic for the better part of that year.

** ACS 5-year estimates for 2024 were not available at the time of this analysis.

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3.1 Disconnections analysis: Demographic variables

- Median Home Value
- Percentage Minority Population
- Percentage Below Poverty Population
- Unemployment Rate
- Percentage Renters
- Percentage of Homes Built after 1990
- Population Density

* Selection of independent variables was informed by previous work on the topic by Pradhan and Chan (2024).

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3.1 Disconnections regression analysis: Results

When all other modeled variables, as well as county-level and year factors, are held constant:

- **Median Home Value**: A $10,000 increase in a census tract's Median Home Value is associated with a decrease of 1.175 disconnections per 1000 households.
- **Percentage Minority Population**: A one percentage-point increase in minority population is associated with an increase of 1.001 disconnections per 1000 households.
- **Percentage Below Poverty Population**: A one percentage-point increase in below poverty population is associated with an increase of 0.634 disconnections per 1000 households.
- **Unemployment Rate**: Not statistically significant at the $p < 0.05$ level.
- **Percentage Renters**: A one percentage-point increase in the percentage of renters is associated with an increase of 0.239 per 1000 households.
- **Percentage of Homes Built after 1990**: A one percentage-point increase in percentage of homes built after 1990 is associated with a decrease of 0.211 disconnections per 1000 households.
- **Population Density**: An increase of 1000 households per square mile is associated with a decrease of 6.969 disconnections per 1000 households.

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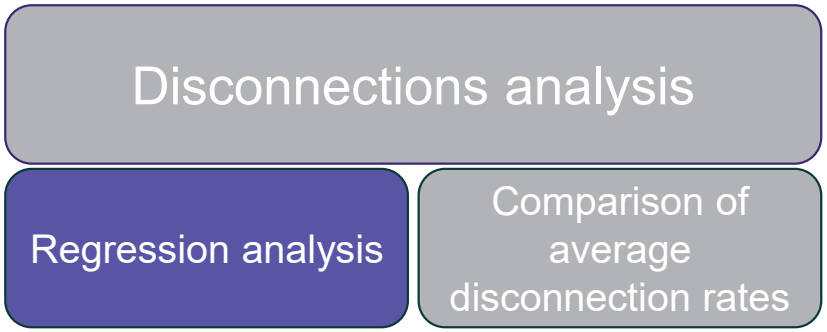
3.1 Disconnections regression analysis: Implications

- Increasing Percentage Minority Population in a census tract is statistically significant and corelated with increasing disconnection rate, even when Percentage Below Poverty and Unemployment Rate are included in the model.
- Census tracts with newer and more expensive homes tend to experience lower disconnection rates than other census tracts when all other modeled variables are held constant.
- As Percentage Renters in a census tract increases, the disconnection rate of the census tract tends to increase when all other modeled variables are held constant.

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3.1 Disconnections regression analysis: Summary

1. What correlations exist between demographic characteristics and disconnection rates?
   - When all other variables are held constant, increasing Percentage Minority Population in a census tract is statistically significant and associated with increasing disconnection rate.
   - Percentage Below Poverty, Population Density, Median Home Value, Percentage of Homes Built After 1990, and Percentage Renters also have statistically significant correlations with disconnection rate.



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3.2 Disconnections & reliability analysis: Overview

2. Do communities with the worst reliability also have higher disconnection rates than other communities?
   - **Methods**: Binary difference-in-means t-test.
   - **Data**: For each 2020 census tract in Consumers' service territory:
     - Count of disconnections in each year (2020-2024) → disconnection rate
     - 18 reliability metrics in each year (2020-2024)

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3.2 Disconnections & reliability analysis: Procedure

For each reliability metric in each year:

1. Divided census tracts into groups.
   - The 10% of census tracts with the worst reliability → "Vulnerable"
   - All other census tracts → "Non-Vulnerable"
2. Computed the average disconnection rate of Vulnerable and Non-Vulnerable groups.
3. Assessed the statistical significance of the difference in average disconnection rate between Vulnerable and Non-Vulnerable groups.
4. If statistically significant, determined which group experienced a worse (higher) average disconnection rate.

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3.2 Disconnections & reliability analysis: Results

When statistically significant differences exist, census tracts with the worst reliability typically have lower average disconnection rates than all other census tracts.

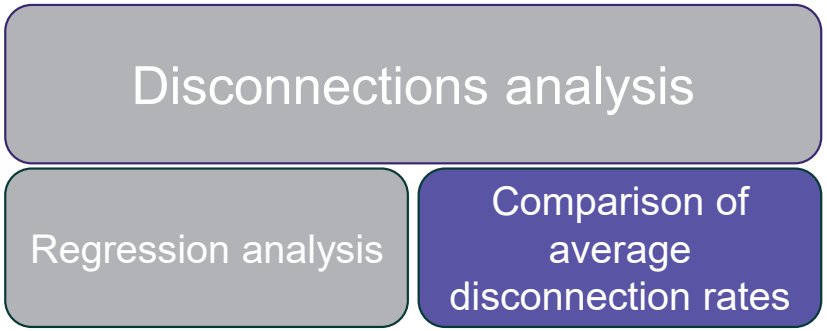
Excerpt of Table 26.

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
Total Customer Interruptions	2020	1.49E+01	1.47E+01	1.51E-01	8.69E-01	FALSE	N/A
	2021	5.27E+01	3.78E+01	1.50E+01	2.11E-10	TRUE	Non-vulnerable
	2022	5.08E+01	3.80E+01	1.28E+01	1.14E-07	TRUE	Non-vulnerable
	2023	5.86E+01	4.16E+01	1.69E+01	5.44E-09	TRUE	Non-vulnerable
	2024	6.72E+01	5.31E+01	1.41E+01	1.79E-06	TRUE	Non-vulnerable
SAIDI including MEDS	2020	1.50E+01	1.38E+01	1.15E+00	2.43E-01	FALSE	N/A
	2021	5.31E+01	3.37E+01	1.94E+01	1.73E-13	TRUE	Non-vulnerable
	2022	5.06E+01	3.95E+01	1.11E+01	3.59E-04	TRUE	Non-vulnerable
	2023	5.85E+01	4.19E+01	1.66E+01	6.05E-07	TRUE	Non-vulnerable
	2024	6.68E+01	5.67E+01	1.01E+01	2.22E-02	TRUE	Non-vulnerable
SAIDI excluding MEDs	2020	1.52E+01	1.20E+01	3.17E+00	1.09E-04	TRUE	Non-vulnerable
	2021	5.28E+01	3.57E+01	1.72E+01	7.81E-09	TRUE	Non-vulnerable
	2022	5.09E+01	3.60E+01	1.49E+01	1.96E-04	TRUE	Non-vulnerable
	2023	5.83E+01	4.37E+01	1.46E+01	1.08E-03	TRUE	Non-vulnerable
	2024	6.74E+01	5.10E+01	1.63E+01	6.49E-04	TRUE	Non-vulnerable
SAIFI including MEDs	2020	1.51E+01	1.29E+01	2.24E+00	2.36E-02	TRUE	Non-vulnerable
	2021	5.29E+01	3.52E+01	1.78E+01	3.46E-07	TRUE	Non-vulnerable
	2022	5.08E+01	3.74E+01	1.33E+01	3.18E-04	TRUE	Non-vulnerable
	2023	5.87E+01	3.98E+01	1.89E+01	3.93E-06	TRUE	Non-vulnerable
	2024	6.73E+01	5.17E+01	1.56E+01	8.75E-04	TRUE	Non-vulnerable

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3.2 Disconnections & reliability analysis: Summary

2. Do communities with the worst reliability also have higher disconnection rates than other communities?
   - No: the comparisons did not show evidence that census tracts with the worst reliability also have higher disconnection rates than other census tracts.



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4. Key Takeaways

- Reliability
  - At the census-tract level, increasing MiEJScreen Overall Score and increasing Percent Minority Percentile are often associated with improving reliability.
  - However, feeders that serve EJ census tracts tend to have more frequent outages (excluding and including MEDs) than other feeders.
- Disconnections
  - When all other variables are held constant, increasing Percentage Minority Population in a census tract is statistically significant and associated with increasing disconnection rate.
  - The 10% of census tracts with the worst reliability typically have lower average disconnection rates than all other census tracts.

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5. Next Steps

- **Dashboard development**: Interactive format to inspect data and results.

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Thank you!

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-21870

EXHIBITS

OF

JON J. KOETJE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Karn Units 1 & 2 Decommissioning Plan Expenditures

Case No.: U-21870
Exhibit No.: A-139 (JJK-1)
Page: 1 of 1
Witness: JJKoetje
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
	Period	**2022-2026**		**2024**		
Line No.	**Activity**	**Projected (2023)**	**Actual and Projected (2024)**	**Projected**	**Actual**	**Variance**
1	Utility Separation	2,453,260	-	-	247,791	(247,791)
2	Decommissioning	7,628,332	5,013,810	-	256,344	(256,344)
3	Abatement	14,750,163	7,142,460	14,750,163	5,749,772	9,000,391
4	Demolition	26,826,467	21,898,086	11,447,658	9,667,091	1,780,567
5	Asset Recovery	(17,895,829)	(9,917,039)	(7,200,000)	(3,977,582)	(3,222,418)
6	Environmental	9,645,887	6,773,082	7,119,982	5,157,214	1,962,768
7	Restoration	4,502,339	10,139,665	-	4,485,202	(4,485,202)
8	Inventory Write Off	6,971,387	3,663,810	-	228,443	(228,443)
9	Contingency	17,042,850	1,700,000	10,000,000	-	10,000,000
10	Project Indirects	25,129,349	30,905,203	9,429,527	4,996,328	4,433,199
11	Interim COR	-	-	-	(5,516,418)	5,516,418
12	**Total**	97,054,205	77,319,077	45,547,330	21,294,185	24,253,145

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual Coal Ash Disposal Plan Expenditures
($000's)

Case No.: U-21870
Exhibit No.: A-140 (JJK-2)
Page: 1 of 1
Witness: JJKoetje
Date: June 2025

	Site	Actuals
		2024
(a)	**DE Karn**	$ 1,448,223
(b)	**JC Weadock**	$ 19,796,598
(c)	**BC Cobb**	$ 86,264
(d)	**JR Whiting**	$ 85,824
(e)	**JH Campbell**	$ 30,729,853
(f)	**Total**	$ 52,146,763

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
JHC Decommissioning Plan Expenditures

Case No.: U-21870
Exhibit No.: A-141 (JJK-3)
Page: 1 of 1
Witness: JJKoetje
Date: June 2025

	(a)	(b)	(c)
Line No.	**Activity**	**Total Project Acual and Projected**	**2024 Actual**
1	Utility Separation	1,002,583	
2	Decommissioning	51,222,820	74,742
3	Abatement	-	
4	Demolition	174,896,148	
5	Asset Recovery	-	(72,421)
6	Environmental	2,715,549	
7	Restoration	2,659,908	
8	Inventory Write Off	22,687,901	
9	Contingency	44,697,968	
10	Project Indirects	80,117,124	5,043,684
11	Interim COR	-	197,739
11	**Total**	380,000,000	5,243,744

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-142 (SAM-1)
Page: 1 of 2
Witness: SAMcPhail
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2025-2026 Bridge Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
1	Grid Automation	LSEN25_ASHLEY_GARFIELD	$12,264	4	Sensor	Automation - Line Sensors	WASHINGTON Township	Customers Impacted	501
2	Grid Automation	LSEN25_ASHMAN CIRCLE_ASHMAN	$55,188	18	Sensor	Automation - Line Sensors	MIDLAND	Customers Impacted	1794
3	Grid Automation	LSEN25_BARRYTON_BARRYTON	$18,396	6	Sensor	Automation - Line Sensors	ORIENT Township	Customers Impacted	706
4	Grid Automation	LSEN25_BARRYTON_CHIPPEWA LAKE	$27,594	9	Sensor	Automation - Line Sensors	SHERIDAN Township	Customers Impacted	1186
5	Grid Automation	LSEN25_BATES_WILLIAMSBURG	$30,660	10	Sensor	Automation - Line Sensors	ACME Township	Customers Impacted	382
6	Grid Automation	LSEN25_BEERS_BALDWIN ROAD	$73,584	24	Sensor	Automation - Line Sensors	GAINES Township	Customers Impacted	1234
7	Grid Automation	LSEN25_BEERS_NICHOLS	$49,056	16	Sensor	Automation - Line Sensors	ARGENTINE Township	Customers Impacted	1070
8	Grid Automation	LSEN25_BEERS_SHARP	$21,462	7	Sensor	Automation - Line Sensors	GAINES Township	Customers Impacted	523
9	Grid Automation	LSEN25_BELLA VISTA_BELLA VISTA	$9,198	3	Sensor	Automation - Line Sensors	CANNON Township	Customers Impacted	648
10	Grid Automation	LSEN25_BELLA VISTA_BLAKELY	$18,396	6	Sensor	Automation - Line Sensors	PLAINFIELD Township	Customers Impacted	962
11	Grid Automation	LSEN25_BENNETT_JOLLY ROAD	$15,330	5	Sensor	Automation - Line Sensors	MERIDIAN Township	Customers Impacted	1241
12	Grid Automation	LSEN25_BIRCHWOOD_BIRCHWOOD	$18,396	6	Sensor	Automation - Line Sensors	CASCADE Township	Customers Impacted	648
13	Grid Automation	LSEN25_BIRCHWOOD_KENMORE	$18,396	6	Sensor	Automation - Line Sensors	ADA Township	Customers Impacted	751
14	Grid Automation	LSEN25_BIRCHWOOD_LARAWAY LAKE	$18,396	6	Sensor	Automation - Line Sensors	ADA Township	Customers Impacted	615
15	Grid Automation	LSEN25_BROADMOOR_AIRWEST	$9,198	3	Sensor	Automation - Line Sensors	KENTWOOD	Customers Impacted	115
16	Grid Automation	LSEN25_BROADMOOR_BARDEN	$9,198	3	Sensor	Automation - Line Sensors	KENTWOOD	Customers Impacted	168
17	Grid Automation	LSEN25_BROADMOOR_MEADOWLANE	$27,594	9	Sensor	Automation - Line Sensors	KENTWOOD	Customers Impacted	2121
18	Grid Automation	LSEN25_BROADMOOR_NORTH	$18,396	6	Sensor	Automation - Line Sensors	FREEDOM Township	Customers Impacted	2003
19	Grid Automation	LSEN25_BROADWAY_BLACK CREEK	$24,528	8	Sensor	Automation - Line Sensors	FRUITPORT Township	Customers Impacted	1059
20	Grid Automation	LSEN25_BROADWAY_PHILLIPS	$6,132	2	Sensor	Automation - Line Sensors	MUSKEGON Township	Customers Impacted	1804
21	Grid Automation	LSEN25_BRONSON_MONROE LAKE	$6,132	2	Sensor	Automation - Line Sensors	BRONSON Township	Customers Impacted	355
22	Grid Automation	LSEN25_CADILLAC_BERRY LAKE	$27,594	9	Sensor	Automation - Line Sensors	CLAM LK Township	Customers Impacted	470
23	Grid Automation	LSEN25_CADILLAC_BOND	$18,396	6	Sensor	Automation - Line Sensors	HARING Township	Customers Impacted	1627
24	Grid Automation	LSEN25_CADILLAC_CENTRAL	$9,198	3	Sensor	Automation - Line Sensors	CADILLAC	Customers Impacted	1323
25	Grid Automation	LSEN25_CADILLAC_HOSPITAL	$45,990	15	Sensor	Automation - Line Sensors	ADRIAN Township	Customers Impacted	1721
26	Grid Automation	LSEN25_CALVIN_BELTLINE	$9,198	3	Sensor	Automation - Line Sensors	GRAND RAPIDS	Customers Impacted	848
27	Grid Automation	LSEN25_CALVIN_FOREST HILLS	$27,594	9	Sensor	Automation - Line Sensors	GRAND RAPIDS Township	Customers Impacted	2074
28	Grid Automation	LSEN25_CALVIN_ROSEMONT	$15,330	5	Sensor	Automation - Line Sensors	E GD RAPIDS	Customers Impacted	1375
29	Grid Automation	LSEN25_CASCADE_PEACE STREET	$45,990	15	Sensor	Automation - Line Sensors	LOWELL Township	Customers Impacted	1458
30	Grid Automation	LSEN25_CASCADE_RIVER	$9,198	3	Sensor	Automation - Line Sensors	CASCADE Township	Customers Impacted	612
31	Grid Automation	LSEN25_CASCADE_THORNCREST	$39,858	13	Sensor	Automation - Line Sensors	LOWELL Township	Customers Impacted	1467
32	Grid Automation	LSEN25_EASTWOOD_EAST	$30,660	10	Sensor	Automation - Line Sensors	KALAMAZOO Township	Customers Impacted	1053
33	Grid Automation	LSEN25_EASTWOOD_NAZARETH	$45,990	15	Sensor	Automation - Line Sensors	KALAMAZOO Township	Customers Impacted	1160
34	Grid Automation	LSEN25_EASTWOOD_TEXEL	$67,452	22	Sensor	Automation - Line Sensors	KALAMAZOO Township	Customers Impacted	1764
35	Grid Automation	LSEN25_EDGEWOOD_DISTRIBUTION	$15,330	5	Sensor	Automation - Line Sensors	LAFAYETTE Township	Customers Impacted	528
36	Grid Automation	LSEN25_ELM STREET_CHAMPION	$30,660	10	Sensor	Automation - Line Sensors	BATTLE CREEK	Customers Impacted	1195
37	Grid Automation	LSEN25_ELM STREET_MAIN	$18,396	6	Sensor	Automation - Line Sensors	EMMETT Township	Customers Impacted	1146
38	Grid Automation	LSEN25_ELM STREET_PORTER	$27,594	9	Sensor	Automation - Line Sensors	EMMETT Township	Customers Impacted	1675
39	Grid Automation	LSEN25_ELM STREET_VERONA	$36,792	12	Sensor	Automation - Line Sensors	PENNFIELD Township	Customers Impacted	2391
40	Grid Automation	LSEN25_FLETCHER_BAY VIEW	$18,396	6	Sensor	Automation - Line Sensors	BEAR CREEK Township	Customers Impacted	614
41	Grid Automation	LSEN25_FLETCHER_ODEN	$24,528	8	Sensor	Automation - Line Sensors	TUSCARORA Township	Customers Impacted	1872
42	Grid Automation	LSEN25_FORDYCE_BAMBER	$52,122	17	Sensor	Automation - Line Sensors	UNION Township	Customers Impacted	1285
43	Grid Automation	LSEN25_FORDYCE_LINCOLN	$36,792	12	Sensor	Automation - Line Sensors	UNION Township	Customers Impacted	825
44	Grid Automation	LSEN25_FRANKFORT_CRYSTALLIA	$21,462	7	Sensor	Automation - Line Sensors	LAKE Township	Customers Impacted	1957
45	Grid Automation	LSEN25_FRANKFORT_ELBERTA	$9,198	3	Sensor	Automation - Line Sensors	BLAINE Township	Customers Impacted	908
46	Grid Automation	LSEN25_FRANKFORT_GATEWAY	$15,330	5	Sensor	Automation - Line Sensors	BENZONIA Township	Customers Impacted	588
47	Grid Automation	LSEN25_GILSON_WYMAN	$36,792	12	Sensor	Automation - Line Sensors	MILLBROOK Township	Customers Impacted	781
48	Grid Automation	LSEN25_GRAND BLANC_GRAND BLANC	$9,198	3	Sensor	Automation - Line Sensors	GRAND BLANC Township	Customers Impacted	1295
49	Grid Automation	LSEN25_GRAND LEDGE_ACADEMY	$61,320	20	Sensor	Automation - Line Sensors	HOLLY Township	Customers Impacted	2261
50	Grid Automation	LSEN25_GRAND LEDGE_HARTEL ROAD	$61,320	20	Sensor	Automation - Line Sensors	ONEIDA Township	Customers Impacted	1763
51	Grid Automation	LSEN25_GRAND LEDGE_WILLOW	$55,188	18	Sensor	Automation - Line Sensors	ONEIDA Township	Customers Impacted	1044
52	Grid Automation	LSEN25_GRAND RIVER_GRAND RIVER	$45,990	15	Sensor	Automation - Line Sensors	PLAINFIELD Township	Customers Impacted	1217
53	Grid Automation	LSEN25_GRAND RIVER_TIHART	$27,594	9	Sensor	Automation - Line Sensors	MERIDIAN Township	Customers Impacted	1310
54	Grid Automation	LSEN25_HAGADORN_BEAUMONT	$27,594	9	Sensor	Automation - Line Sensors	MERIDIAN Township	Customers Impacted	885
55	Grid Automation	LSEN25_HAGADORN_HAGADORN	$21,462	7	Sensor	Automation - Line Sensors	MERIDIAN Township	Customers Impacted	889
56	Grid Automation	LSEN25_HOSPITAL_ELMWOOD	$82,782	27	Sensor	Automation - Line Sensors	BINGHAM Township	Customers Impacted	1924
57	Grid Automation	LSEN25_HOSPITAL_KIDS CREEK	$18,396	6	Sensor	Automation - Line Sensors	GARFIELD Township	Customers Impacted	141
58	Grid Automation	LSEN25_HUBBARDSTON ROAD_HUBBARDSTON	$21,462	7	Sensor	Automation - Line Sensors	N PLAINS Township	Customers Impacted	429
59	Grid Automation	LSEN25_HUBBARDSTON ROAD_STONEY CREEK	$9,198	3	Sensor	Automation - Line Sensors	DALLAS Township	Customers Impacted	464
60	Grid Automation	LSEN25_JASPER_LAPORTE	$39,858	13	Sensor	Automation - Line Sensors	JONESFIELD Township	Customers Impacted	424
61	Grid Automation	LSEN25_JASPER_REDSTONE	$33,726	11	Sensor	Automation - Line Sensors	JASPER Township	Customers Impacted	432
62	Grid Automation	LSEN25_JEFFS ROAD_U.S. 23	$9,198	3	Sensor	Automation - Line Sensors	WHITEFORD Township	Customers Impacted	232
63	Grid Automation	LSEN25_KEARSLEY_BRIAR LANE	$3,066	1	Sensor	Automation - Line Sensors	GENESEE Township	Customers Impacted	455
64	Grid Automation	LSEN25_KEARSLEY_COVERT ROAD	$15,330	5	Sensor	Automation - Line Sensors	GENESEE Township	Customers Impacted	1076
65	Grid Automation	LSEN25_KEARSLEY_CROSBY ROAD	$18,396	6	Sensor	Automation - Line Sensors	GENESEE Township	Customers Impacted	1257
66	Grid Automation	LSEN25_KENDALL_SAGE	$27,594	9	Sensor	Automation - Line Sensors	OSHTEMO Township	Customers Impacted	2448
67	Grid Automation	LSEN25_KENDALL_WESTWOOD	$18,396	6	Sensor	Automation - Line Sensors	KALAMAZOO Township	Customers Impacted	1598
68	Grid Automation	LSEN25_KENTWOOD_PARIS PARK	$36,792	12	Sensor	Automation - Line Sensors	GAINES Township	Customers Impacted	2657
69	Grid Automation	LSEN25_KENTWOOD_PRINCETON	$18,396	6	Sensor	Automation - Line Sensors	KENTWOOD	Customers Impacted	1803
70	Grid Automation	LSEN25_KENTWOOD_STAUFFER	$9,198	3	Sensor	Automation - Line Sensors	GRAND RAPIDS	Customers Impacted	3004
71	Grid Automation	LSEN25_LITCHFIELD_QUAKER LAKE	$61,320	20	Sensor	Automation - Line Sensors	CLARENDON Township	Customers Impacted	696
72	Grid Automation	LSEN25_LYONS_COLLINS-RURAL	$24,528	8	Sensor	Automation - Line Sensors	IONIA Township	Customers Impacted	301
73	Grid Automation	LSEN25_LYONS_LYONS-MUIR	$64,386	21	Sensor	Automation - Line Sensors	N PLAINS Township	Customers Impacted	916
74	Grid Automation	LSEN25_MANISTEE_FILER CITY	$18,396	6	Sensor	Automation - Line Sensors	FILER Township	Customers Impacted	580
75	Grid Automation	LSEN25_MANISTEE_LAKE MICHIGAN	$9,198	3	Sensor	Automation - Line Sensors	FILER Township	Customers Impacted	2150
76	Grid Automation	LSEN25_MANISTEE_MANISTEE SALT	$9,198	3	Sensor	Automation - Line Sensors	FILER Township	Customers Impacted	461
77	Grid Automation	LSEN25_MANISTEE_PARKDALE	$27,594	9	Sensor	Automation - Line Sensors	MANISTEE	Customers Impacted	1212
78	Grid Automation	LSEN25_MICOR_LOSEY	$45,990	15	Sensor	Automation - Line Sensors	JACKSON	Customers Impacted	170
79	Grid Automation	LSEN25_MICOR_WELLWORTH	$30,660	10	Sensor	Automation - Line Sensors	NAPOLEON Township	Customers Impacted	493
80	Grid Automation	LSEN25_MILLER ROAD_UTLEY ROAD	$33,726	11	Sensor	Automation - Line Sensors	FLINT Township	Customers Impacted	539
81	Grid Automation	LSEN25_MILLER ROAD_YALE STREET	$18,396	6	Sensor	Automation - Line Sensors	FLINT Township	Customers Impacted	1108
82	Grid Automation	LSEN25_MILLERS POINT_ARCADIA	$9,198	3	Sensor	Automation - Line Sensors	KALAMAZOO	Customers Impacted	3077
83	Grid Automation	LSEN25_MILLERS POINT_CONCORD	$9,198	3	Sensor	Automation - Line Sensors	OSHTEMO Township	Customers Impacted	3942
84	Grid Automation	LSEN25_MILLERS POINT_HOLIDAY	$27,594	9	Sensor	Automation - Line Sensors	FLINT Township	Customers Impacted	2299
85	Grid Automation	LSEN25_MILLERS POINT_MEADOW VIEW	$27,594	9	Sensor	Automation - Line Sensors	KALAMAZOO	Customers Impacted	910
86	Grid Automation	LSEN25_MONTAGUE_DOWLING	$24,528	8	Sensor	Automation - Line Sensors	JOHNSTOWN Township	Customers Impacted	1589
87	Grid Automation	LSEN25_MONTEREY_30TH STREET	$21,462	7	Sensor	Automation - Line Sensors	SALEM Township	Customers Impacted	588
88	Grid Automation	LSEN25_MONTEREY_KNELLER	$18,396	6	Sensor	Automation - Line Sensors	SALEM Township	Customers Impacted	118
89	Grid Automation	LSEN25_OKEMOS_WKAR	$45,990	15	Sensor	Automation - Line Sensors	MERIDIAN Township	Customers Impacted	1085
90	Grid Automation	LSEN25_PINE RIVER_GRATIOT	$9,198	3	Sensor	Automation - Line Sensors	SAGINAW Township	Customers Impacted	842
91	Grid Automation	LSEN25_PINE RIVER_RURAL	$45,990	15	Sensor	Automation - Line Sensors	SEVILLE Township	Customers Impacted	1069
92	Grid Automation	LSEN25_ROBERTS STREET_BENDER	$18,396	6	Sensor	Automation - Line Sensors	BLACKMAN Township	Customers Impacted	487
93	Grid Automation	LSEN25_ROBERTS STREET_DETTMAN	$36,792	12	Sensor	Automation - Line Sensors	BLACKMAN Township	Customers Impacted	1147
94	Grid Automation	LSEN25_ROBERTS STREET_FOOTE HOSPITAL	$9,198	3	Sensor	Automation - Line Sensors	BLACKMAN Township	Customers Impacted	362
95	Grid Automation	LSEN25_ROBERTS STREET_LEROY STREET	$49,056	16	Sensor	Automation - Line Sensors	BLACKMAN Township	Customers Impacted	1557
96	Grid Automation	LSEN25_ROSEBUSH_DELWIN	$55,188	18	Sensor	Automation - Line Sensors	GENEVA Township	Customers Impacted	846
97	Grid Automation	LSEN25_ROSEBUSH_STEVENSON LAKE	$64,386	21	Sensor	Automation - Line Sensors	VERNON Township	Customers Impacted	721
98	Grid Automation	LSEN25_SHELBY_PINE STREET	$15,330	5	Sensor	Automation - Line Sensors	SHELBY Township	Customers Impacted	495
99	Grid Automation	LSEN25_SHELBY_STATE STREET	$24,528	8	Sensor	Automation - Line Sensors	SHELBY Township	Customers Impacted	703
100	Grid Automation	LSEN25_SLOAN_LAVELLE ROAD	$42,924	14	Sensor	Automation - Line Sensors	FLINT	Customers Impacted	1063
101	Grid Automation	LSEN25_SUMMIT_FOURTH STREET	$21,462	7	Sensor	Automation - Line Sensors	SUMMIT Township	Customers Impacted	1743
102	Grid Automation	LSEN25_SUMMIT_FRANCIS STREET	$6,132	2	Sensor	Automation - Line Sensors	SUMMIT Township	Customers Impacted	1488
103	Grid Automation	LSEN25_SUMMIT_SOUTH STREET	$9,198	3	Sensor	Automation - Line Sensors	SUMMIT Township	Customers Impacted	457
104	Grid Automation	LSEN25_TRUFANT_GOWEN	$67,452	22	Sensor	Automation - Line Sensors	MONTCALM Township	Customers Impacted	1108
105	Grid Automation	LSEN25_TRUFANT_HUNTER LAKE	$58,254	19	Sensor	Automation - Line Sensors	DOUGLASS Township	Customers Impacted	994
106	Grid Automation	LSEN25_TRUFANT_MASTON LAKE	$30,660	10	Sensor	Automation - Line Sensors	MAPLE VALLEY Township	Customers Impacted	648
107	Grid Automation	LSEN25_TRUFANT_TRUFANT	$21,462	7	Sensor	Automation - Line Sensors	MAPLE VALLEY Township	Customers Impacted	501
108	Grid Automation	LSEN25_WAGER_PARKLAND	$39,858	13	Sensor	Automation - Line Sensors	FLINT	Customers Impacted	1114
109	Grid Automation	LSEN25_WESTWOOD_DURAND	$18,396	6	Sensor	Automation - Line Sensors	BLACKMAN Township	Customers Impacted	1330
110	Grid Automation	Credit for material purchased in previous spending period	-$2,133,000						
111	Grid Automation	AMPLE (Line Sensor SAAS (estimate))	$3,100,000						
112	Grid Automation	RAMP	$2,083,000						
			$6,116,000	**1000**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2025-2026 Bridge Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
1	Grid Automation	REG25_ALCONA DAM_CURTISVILLE	$35,803	1	Regulator Location	Automation - Regulator Controllers	CURTIS Township	Customers Impacted	383
2	Grid Automation	REG25_ALCONA DAM_GLENNIE	$71,606	2	Regulator Location	Automation - Regulator Controllers	CURTIS Township	Customers Impacted	1445
3	Grid Automation	REG25_ALGER_SKIDWAY	$35,803	1	Regulator Location	Automation - Regulator Controllers	RICHLAND Township	Customers Impacted	1217
4	Grid Automation	REG25_AU GRES_AU GRES	$107,409	3	Regulator Location	Automation - Regulator Controllers	AU GRES Township	Customers Impacted	74
5	Grid Automation	REG25_AU GRES_POINT LOOK-OUT	$35,803	1	Regulator Location	Automation - Regulator Controllers	SIMS Township	Customers Impacted	371
6	Grid Automation	REG25_BAILEY_BAILEY	$35,803	1	Regulator Location	Automation - Regulator Controllers	ASHLAND Township	Customers Impacted	208
7	Grid Automation	REG25_BAILEY_CHERRY	$35,803	1	Regulator Location	Automation - Regulator Controllers	ASHLAND Township	Customers Impacted	110
8	Grid Automation	REG25_BALDWIN_IDLEWILD	$35,803	1	Regulator Location	Automation - Regulator Controllers	SWEETWATER Township	Customers Impacted	326
9	Grid Automation	REG25_BASS LAKE_CARTER	$35,803	1	Regulator Location	Automation - Regulator Controllers	RIVERTON Township	Customers Impacted	419
10	Grid Automation	REG25_BASS LAKE_KISTLER	$71,606	2	Regulator Location	Automation - Regulator Controllers	PERE MARQUETTE Township	Customers Impacted	310
11	Grid Automation	REG25_BATH_BATH	$143,212	4	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	586
12	Grid Automation	REG25_BATH_PARK LAKE	$35,803	1	Regulator Location	Automation - Regulator Controllers	VICTOR Township	Customers Impacted	202
13	Grid Automation	REG25_BELDING_CITY	$35,803	1	Regulator Location	Automation - Regulator Controllers	OGDEN Township	Customers Impacted	218
14	Grid Automation	REG25_BESSINGER_QUARRY	$107,409	3	Regulator Location	Automation - Regulator Controllers	ARENAC Township	Customers Impacted	404
15	Grid Automation	REG25_BLUEGRASS_SUMMERTON	$35,803	1	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	36
16	Grid Automation	REG25_BUCKENRIDGE_WHEELER	$35,803	1	Regulator Location	Automation - Regulator Controllers	LAFAYETTE Township	Customers Impacted	114
17	Grid Automation	REG25_CEDAR LAKE_VAN ETTEN	$71,606	2	Regulator Location	Automation - Regulator Controllers	OSCODA Township	Customers Impacted	615
18	Grid Automation	REG25_CONKLIN PARK_CROTON	$35,803	1	Regulator Location	Automation - Regulator Controllers	BIG PRAIRIE Township	Customers Impacted	504
19	Grid Automation	REG25_CONKLIN PARK_HOLLY	$143,212	4	Regulator Location	Automation - Regulator Controllers	REYNOLDS Township	Customers Impacted	611
20	Grid Automation	REG25_COWAN LAKE_GRATTAN	$71,606	2	Regulator Location	Automation - Regulator Controllers	GRATTAN Township	Customers Impacted	73
21	Grid Automation	REG25_DERBY_DERBY	$35,803	1	Regulator Location	Automation - Regulator Controllers	DOUGLASS Township	Customers Impacted	110
22	Grid Automation	REG25_DUQUITE_JOHNSFIELD	$35,803	1	Regulator Location	Automation - Regulator Controllers	STANDISH Township	Customers Impacted	161
23	Grid Automation	REG25_EAST LAKE_CHEMICAL	$35,803	1	Regulator Location	Automation - Regulator Controllers	MANISTEE Township	Customers Impacted	170
24	Grid Automation	REG25_EAST LAKE_PINE CREEK	$71,606	2	Regulator Location	Automation - Regulator Controllers	MANISTEE Township	Customers Impacted	409
25	Grid Automation	REG25_EAST TAWAS_ALABASTER	$35,803	1	Regulator Location	Automation - Regulator Controllers	TAWAS Township	Customers Impacted	462
26	Grid Automation	REG25_EDMORE_SIX LAKES	$179,015	5	Regulator Location	Automation - Regulator Controllers	BELVIDERE Township	Customers Impacted	715
27	Grid Automation	REG25_ENSLEY_DISTRIBUTION	$179,015	5	Regulator Location	Automation - Regulator Controllers	LAFAYETTE Township	Customers Impacted	782
28	Grid Automation	REG25_FIVE CHANNELS HYDRO_DISTRIBUTION	$35,803	1	Regulator Location	Automation - Regulator Controllers	LAFAYETTE Township	Customers Impacted	203
29	Grid Automation	REG25_FOUR MILE_BAUMHOFF	$35,803	1	Regulator Location	Automation - Regulator Controllers	ALPINE Township	Customers Impacted	161
30	Grid Automation	REG25_FOUR MILE_WALKENT	$71,606	2	Regulator Location	Automation - Regulator Controllers	GRAND RAPIDS	Customers Impacted	83
31	Grid Automation	REG25_FREEPORT_BOWNE CENTER	$143,212	4	Regulator Location	Automation - Regulator Controllers	BOWNE Township	Customers Impacted	602
32	Grid Automation	REG25_FREEPORT_CARLTON CENTER	$107,409	3	Regulator Location	Automation - Regulator Controllers	BOWNE Township	Customers Impacted	375
33	Grid Automation	REG25_GERRISH_COTTAGE GROVE	$107,409	3	Regulator Location	Automation - Regulator Controllers	HIGGINS Township	Customers Impacted	568
34	Grid Automation	REG25_GERRISH_GOLF CLUB	$107,409	3	Regulator Location	Automation - Regulator Controllers	CLAM LK Township	Customers Impacted	538
35	Grid Automation	REG25_GERRISH_LEGION	$179,015	5	Regulator Location	Automation - Regulator Controllers	GRAYLING Township	Customers Impacted	530
36	Grid Automation	REG25_GILSON_WYMAN	$35,803	1	Regulator Location	Automation - Regulator Controllers	MILLBROOK Township	Customers Impacted	41
37	Grid Automation	REG25_GRAND LEDGE_WILLOW	$35,803	1	Regulator Location	Automation - Regulator Controllers	ONEIDA Township	Customers Impacted	530
38	Grid Automation	REG25_GREENWOOD_INDIAN LAKE	$71,606	2	Regulator Location	Automation - Regulator Controllers	BRADY Township	Customers Impacted	727
39	Grid Automation	REG25_GREENWOOD_RAU ROAD	$107,409	3	Regulator Location	Automation - Regulator Controllers	MOFFATT Township	Customers Impacted	481
40	Grid Automation	REG25_GUN LAKE_ENGLAND	$35,803	1	Regulator Location	Automation - Regulator Controllers	ORANGEVILLE Township	Customers Impacted	1303
41	Grid Automation	REG25_HARRIETTA_BOON	$35,803	1	Regulator Location	Automation - Regulator Controllers	DICKSON Township	Customers Impacted	73
42	Grid Automation	REG25_HARRIETTA_CABERFAE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BOON Township	Customers Impacted	169
43	Grid Automation	REG25_HIGH BRIDGE_KALEVA	$35,803	1	Regulator Location	Automation - Regulator Controllers	KALEVA	Customers Impacted	340
44	Grid Automation	REG25_HOLTON_MAPLE ISLAND	$71,606	2	Regulator Location	Automation - Regulator Controllers	DAYTON Township	Customers Impacted	340
45	Grid Automation	REG25_HONOR_PLATTE	$35,803	1	Regulator Location	Automation - Regulator Controllers	HOMESTEAD Township	Customers Impacted	835
46	Grid Automation	REG25_HOUGHTON HEIGHTS_MERRITT	$107,409	3	Regulator Location	Automation - Regulator Controllers	BUTTERFIELD Township	Customers Impacted	746
47	Grid Automation	REG25_HOUGHTON HEIGHTS_PRUDENVILLE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BUTTERFIELD Township	Customers Impacted	556
48	Grid Automation	REG25_HOWARD CITY_MORLEY	$35,803	1	Regulator Location	Automation - Regulator Controllers	REYNOLDS Township	Customers Impacted	137
49	Grid Automation	REG25_ITHACA_COURT HOUSE	$35,803	1	Regulator Location	Automation - Regulator Controllers	NEWARK Township	Customers Impacted	377
50	Grid Automation	REG25_ITHACA_FAIR GROUNDS	$143,212	4	Regulator Location	Automation - Regulator Controllers	NEWARK Township	Customers Impacted	14
51	Grid Automation	REG25_KENT CITY_CASNOVIA	$143,212	4	Regulator Location	Automation - Regulator Controllers	SPARTA Township	Customers Impacted	597
52	Grid Automation	REG25_KINGSLEY_CENTER ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	HAMPTON Township	Customers Impacted	145
53	Grid Automation	REG25_LAKE CITY_JENNINGS	$35,803	1	Regulator Location	Automation - Regulator Controllers	REEDER Township	Customers Impacted	146
54	Grid Automation	REG25_LAKE CITY_STITTSVILLE	$71,606	2	Regulator Location	Automation - Regulator Controllers	REEDER Township	Customers Impacted	1398
55	Grid Automation	REG25_LAKE MITCHELL_GOLF CLUB	$35,803	1	Regulator Location	Automation - Regulator Controllers	CLAM LK Township	Customers Impacted	412
56	Grid Automation	REG25_LOOMIS_LOOMIS ROAD	$143,212	4	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	409
57	Grid Automation	REG25_LYON MANOR_TREASURE	$35,803	1	Regulator Location	Automation - Regulator Controllers	GERRISH Township	Customers Impacted	592
58	Grid Automation	REG25_LYONS_LYONS-MUIR	$35,803	1	Regulator Location	Automation - Regulator Controllers	N PLAINS Township	Customers Impacted	545
59	Grid Automation	REG25_MARKER LAKE_KYSER ROAD	$71,606	2	Regulator Location	Automation - Regulator Controllers	BOSTON Township	Customers Impacted	407
60	Grid Automation	REG25_MARKEY_CARRICK	$107,409	3	Regulator Location	Automation - Regulator Controllers	GERRISH Township	Customers Impacted	877
61	Grid Automation	REG25_MARKEY_MONTVILLE	$143,212	4	Regulator Location	Automation - Regulator Controllers	DENTON Township	Customers Impacted	1439
62	Grid Automation	REG25_MCBAIN_LAKE CITY	$35,803	1	Regulator Location	Automation - Regulator Controllers	REEDER Township	Customers Impacted	402
63	Grid Automation	REG25_MERRILL_MERRILL	$35,803	1	Regulator Location	Automation - Regulator Controllers	LAFAYETTE Township	Customers Impacted	559
64	Grid Automation	REG25_MT PLEASANT_BROADWAY	$107,409	3	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	662
65	Grid Automation	REG25_MT PLEASANT_COLLEGE	$35,803	1	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	154
66	Grid Automation	REG25_NINETEEN MILE RD_CEMENT	$35,803	1	Regulator Location	Automation - Regulator Controllers	COLFAX Township	Customers Impacted	300
67	Grid Automation	REG25_NINETEEN MILE RD_INDUSTRIAL PARK	$35,803	1	Regulator Location	Automation - Regulator Controllers	BIG RAPIDS Township	Customers Impacted	101
68	Grid Automation	REG25_ORLEANS_ORLEANS	$107,409	3	Regulator Location	Automation - Regulator Controllers	OTISCO Township	Customers Impacted	352
69	Grid Automation	REG25_PALO_CHARLES ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	IONIA Township	Customers Impacted	63
70	Grid Automation	REG25_PALO_PALO	$35,803	1	Regulator Location	Automation - Regulator Controllers	N PLAINS Township	Customers Impacted	215
71	Grid Automation	REG25_PARAMOUNT_NORTHLAND FARMS	$35,803	1	Regulator Location	Automation - Regulator Controllers	PLAINFIELD Township	Customers Impacted	446
72	Grid Automation	REG25_PEWAMO_FOWLER	$35,803	1	Regulator Location	Automation - Regulator Controllers	LEBANON Township	Customers Impacted	726
73	Grid Automation	REG25_PIERSON_PIERSON	$71,606	2	Regulator Location	Automation - Regulator Controllers	MT MORRIS Township	Customers Impacted	566
74	Grid Automation	REG25_PIERSON_WHITEFISH	$71,606	2	Regulator Location	Automation - Regulator Controllers	ENSLEY Township	Customers Impacted	422
75	Grid Automation	REG25_PINE RIVER_RURAL	$71,606	2	Regulator Location	Automation - Regulator Controllers	SEVILLE Township	Customers Impacted	266
76	Grid Automation	REG25_PISTON RING_STEBBINS	$71,606	2	Regulator Location	Automation - Regulator Controllers	SPARTA Township	Customers Impacted	380
77	Grid Automation	REG25_PLAINFIELD_BELMONT	$35,803	1	Regulator Location	Automation - Regulator Controllers	PLAINFIELD Township	Customers Impacted	612
78	Grid Automation	REG25_PLAINFIELD_KUTTSHILL	$35,803	1	Regulator Location	Automation - Regulator Controllers	PLAINFIELD Township	Customers Impacted	274
79	Grid Automation	REG25_PLAINFIELD_WOOD	$71,606	2	Regulator Location	Automation - Regulator Controllers	PLAINFIELD Township	Customers Impacted	543
80	Grid Automation	REG25_PRESCOTT_LOGAN	$107,409	3	Regulator Location	Automation - Regulator Controllers	RICHLAND Township	Customers Impacted	387
81	Grid Automation	REG25_PRESCOTT_MAPLE RIDGE	$143,212	4	Regulator Location	Automation - Regulator Controllers	CARROLLTON Township	Customers Impacted	510
82	Grid Automation	REG25_RATIGAN_MURRAY LAKE	$35,803	1	Regulator Location	Automation - Regulator Controllers	OTISCO Township	Customers Impacted	114
83	Grid Automation	REG25_REED CITY_HOLDENVILLE	$71,606	2	Regulator Location	Automation - Regulator Controllers	LEROY Township	Customers Impacted	244
84	Grid Automation	REG25_REED CITY_MEDICAL	$35,803	1	Regulator Location	Automation - Regulator Controllers	RICHMOND Township	Customers Impacted	52
85	Grid Automation	REG25_REMUS_MECOSTA	$143,212	4	Regulator Location	Automation - Regulator Controllers	WHEATLAND Township	Customers Impacted	1039
86	Grid Automation	REG25_REMUS_MILLBROOK	$107,409	3	Regulator Location	Automation - Regulator Controllers	WHEATLAND Township	Customers Impacted	310
87	Grid Automation	REG25_RIVERDALE_RIVERDALE	$107,409	3	Regulator Location	Automation - Regulator Controllers	SEVILLE Township	Customers Impacted	469
88	Grid Automation	REG25_RIVERDALE_SUMNER	$35,803	1	Regulator Location	Automation - Regulator Controllers	SEVILLE Township	Customers Impacted	495
89	Grid Automation	REG25_ROCKFORD_WOLVERINE	$35,803	1	Regulator Location	Automation - Regulator Controllers	WILMOT Township	Customers Impacted	148
90	Grid Automation	REG25_ROSCOMMON_PIONEER	$71,606	2	Regulator Location	Automation - Regulator Controllers	FLUSHING Township	Customers Impacted	297
91	Grid Automation	REG25_ROSE CITY_ISLAND LAKE	$107,409	3	Regulator Location	Automation - Regulator Controllers	MENTOR Township	Customers Impacted	1232
92	Grid Automation	REG25_SARANAC_KEENE	$71,606	2	Regulator Location	Automation - Regulator Controllers	BOSTON Township	Customers Impacted	115
93	Grid Automation	REG25_SHEPHERD_FOREST HILL	$107,409	3	Regulator Location	Automation - Regulator Controllers	SEVILLE Township	Customers Impacted	379
94	Grid Automation	REG25_SHEPHERD_SHEPHERD	$143,212	4	Regulator Location	Automation - Regulator Controllers	JASPER Township	Customers Impacted	393
95	Grid Automation	REG25_SHERIDAN_FENWICK	$71,606	2	Regulator Location	Automation - Regulator Controllers	EVERGREEN Township	Customers Impacted	394
96	Grid Automation	REG25_SIMMONS_DAM ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	OGEMAW Township	Customers Impacted	116
97	Grid Automation	REG25_ST HELEN_ARTESIA	$71,606	2	Regulator Location	Automation - Regulator Controllers	FOSTER Township	Customers Impacted	1709
98	Grid Automation	REG25_ST HELEN_ST HELEN	$71,606	2	Regulator Location	Automation - Regulator Controllers	AU SABLE Township	Customers Impacted	1266
99	Grid Automation	REG25_STANDISH_STANDISH	$214,818	6	Regulator Location	Automation - Regulator Controllers	ARENAC Township	Customers Impacted	1176
100	Grid Automation	REG25_STANWOOD_TYLER ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	AETNA Township	Customers Impacted	278
101	Grid Automation	REG25_SUNFIELD_MULLIKEN	$143,212	4	Regulator Location	Automation - Regulator Controllers	ORANGE Township	Customers Impacted	749
102	Grid Automation	REG25_SUNFIELD_SUNFIELD	$214,818	6	Regulator Location	Automation - Regulator Controllers	CHESTER Township	Customers Impacted	855
103	Grid Automation	REG25_TAMARACK_AMBLE	$35,803	1	Regulator Location	Automation - Regulator Controllers	REYNOLDS Township	Customers Impacted	120
104	Grid Automation	REG25_TRUFANT_HUNTER LAKE	$71,606	2	Regulator Location	Automation - Regulator Controllers	DOUGLASS Township	Customers Impacted	766
105	Grid Automation	REG25_VANDERBILT_WOLVERINE	$35,803	1	Regulator Location	Automation - Regulator Controllers	WILMOT Township	Customers Impacted	469
106	Grid Automation	REG25_WEST BRANCH_REFINERY	$35,803	1	Regulator Location	Automation - Regulator Controllers	OGEMAW Township	Customers Impacted	188
107	Grid Automation	REG25_WESTPHALIA_GRANGE ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	DALLAS Township	Customers Impacted	27
108	Grid Automation	REG25_WESTPHALIA_PRICE ROAD	$143,212	4	Regulator Location	Automation - Regulator Controllers	DALLAS Township	Customers Impacted	284
109	Grid Automation	REG25_WOODLAND_BARNUM	$35,803	1	Regulator Location	Automation - Regulator Controllers	HASTINGS Township	Customers Impacted	46
110	Grid Automation	REG25_WOODLAND_WOODBURY	$35,803	1	Regulator Location	Automation - Regulator Controllers	WOODLAND Township	Customers Impacted	55
111	Grid Automation	REG26_BLACK RIVER_ZEELAND	$35,803	1	Regulator Location	Automation - Regulator Controllers	HOLLAND Township	Customers Impacted	144
112	Grid Automation	REG26_CONVIS_MAR CREEK	$35,803	1	Regulator Location	Automation - Regulator Controllers	PENNFIELD Township	Customers Impacted	432
113	Grid Automation	REG26_CUTLERVILLE_SPARTAN	$35,803	1	Regulator Location	Automation - Regulator Controllers	BYRON Township	Customers Impacted	375
114	Grid Automation	REG26_DORR CORNERS_RED RUN	$35,803	1	Regulator Location	Automation - Regulator Controllers	DORR Township	Customers Impacted	1197
115	Grid Automation	REG26_EMERSON_KILMER	$35,803	1	Regulator Location	Automation - Regulator Controllers	CALEDONIA Township	Customers Impacted	1106
116	Grid Automation	REG26_FENNVILLE_COMMERCIAL	$35,803	1	Regulator Location	Automation - Regulator Controllers	CLYDE Township	Customers Impacted	160
117	Grid Automation	REG26_FENNVILLE_PEACH BELT	$35,803	1	Regulator Location	Automation - Regulator Controllers	SAUGATUCK Township	Customers Impacted	135
118	Grid Automation	REG26_FINE LAKE_BRISTOL	$35,803	1	Regulator Location	Automation - Regulator Controllers	JOHNSTOWN Township	Customers Impacted	202
119	Grid Automation	REG26_FINE LAKE_DOWLING	$35,803	1	Regulator Location	Automation - Regulator Controllers	JOHNSTOWN Township	Customers Impacted	88
120	Grid Automation	REG26_FOOTE HYDRO_DISTRIBUTION	$35,803	1	Regulator Location	Automation - Regulator Controllers	LAFAYETTE Township	Customers Impacted	338
121	Grid Automation	REG26_FOREMAN_VERGENNES	$35,803	1	Regulator Location	Automation - Regulator Controllers	ADA Township	Customers Impacted	109
122	Grid Automation	REG26_GREENBUSH_GREENBUSH	$35,803	1	Regulator Location	Automation - Regulator Controllers	GREENBUSH Township	Customers Impacted	364
123	Grid Automation	REG26_GREENBUSH_HARRISVILLE	$35,803	1	Regulator Location	Automation - Regulator Controllers	HARRISVILLE Township	Customers Impacted	687
124	Grid Automation	REG26_HAGER PARK_HAGER PARK	$35,803	1	Regulator Location	Automation - Regulator Controllers	GEORGETOWN Township	Customers Impacted	696
125	Grid Automation	REG26_HALLS LAKE_HALLS LAKE	$35,803	1	Regulator Location	Automation - Regulator Controllers	MARENGO Township	Customers Impacted	57
126	Grid Automation	REG26_HARLEM_BORCULO	$35,803	1	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	87
127	Grid Automation	REG26_KENTWOOD_PARIS PARK	$35,803	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	1229
128	Grid Automation	REG26_LABARGE_ALASKA	$71,606	2	Regulator Location	Automation - Regulator Controllers	BOWNE Township	Customers Impacted	560
129	Grid Automation	REG26_LABARGE_BLODGETT LAKE	$107,409	3	Regulator Location	Automation - Regulator Controllers	BOWNE Township	Customers Impacted	1334
130	Grid Automation	REG26_LEVEL PARK_COLLIER	$35,803	1	Regulator Location	Automation - Regulator Controllers	BEDFORD Township	Customers Impacted	79
131	Grid Automation	REG26_LINCOLN_LOST LAKE	$71,606	2	Regulator Location	Automation - Regulator Controllers	GUSTIN Township	Customers Impacted	139
132	Grid Automation	REG26_LINCOLN_MIKADO	$179,015	5	Regulator Location	Automation - Regulator Controllers	GREENBUSH Township	Customers Impacted	527
133	Grid Automation	REG26_MARNE_MARNE	$35,803	1	Regulator Location	Automation - Regulator Controllers	WRIGHT Township	Customers Impacted	333
134	Grid Automation	REG26_MILL GROVE_ALLEGAN HYDRO	$35,803	1	Regulator Location	Automation - Regulator Controllers	ALLEGAN Township	Customers Impacted	272
135	Grid Automation	REG26_MOLINE_MOLINE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BYRON Township	Customers Impacted	548
136	Grid Automation	REG26_MORGAN_ORCHARD	$35,803	1	Regulator Location	Automation - Regulator Controllers	PENNFIELD Township	Customers Impacted	535
137	Grid Automation	REG26_MORGAN_ST MARYS	$179,015	5	Regulator Location	Automation - Regulator Controllers	PENNFIELD Township	Customers Impacted	1067
138	Grid Automation	REG26_NORTHERN FIBRE_FIBRE	$71,606	2	Regulator Location	Automation - Regulator Controllers	HOLLAND Township	Customers Impacted	916
139	Grid Automation	REG26_OLIVET_KINGER	$35,803	1	Regulator Location	Automation - Regulator Controllers	CARMEL Township	Customers Impacted	126
140	Grid Automation	REG26_OLIVET_COLLEGE	$71,606	2	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	259
141	Grid Automation	REG26_OSCODA_BUTLER HEIGHTS	$71,606	2	Regulator Location	Automation - Regulator Controllers	BALDWIN Township	Customers Impacted	864
142	Grid Automation	REG26_PULLMAN_CHICORA	$71,606	2	Regulator Location	Automation - Regulator Controllers	CLYDE Township	Customers Impacted	388
143	Grid Automation	REG26_PULLMAN_PULLMAN	$35,803	1	Regulator Location	Automation - Regulator Controllers	CLYDE Township	Customers Impacted	60
144	Grid Automation	REG26_SALEM_BURNIPS	$35,803	1	Regulator Location	Automation - Regulator Controllers	SALEM Township	Customers Impacted	303
145	Grid Automation	REG26_SHERMAN_SHERMAN	$35,803	1	Regulator Location	Automation - Regulator Controllers	GREENWOOD Township	Customers Impacted	92
146	Grid Automation	REG26_SPRUCE ROAD_BLACK RIVER	$35,803	1	Regulator Location	Automation - Regulator Controllers	CALEDONIA Township	Customers Impacted	368
147	Grid Automation	REG26_TAWAS_TAWAS	$107,409	3	Regulator Location	Automation - Regulator Controllers	TAWAS Township	Customers Impacted	803
148	Grid Automation	REG26_THORNAPPLE_BUTTRICK	$35,803	1	Regulator Location	Automation - Regulator Controllers	ADA Township	Customers Impacted	134
149	Grid Automation	REG26_WALKER_REMEMBRANCE	$35,803	1	Regulator Location	Automation - Regulator Controllers	TALLMADGE Township	Customers Impacted	33
150	Grid Automation	REG26_WAKESHMA_FULTON	$35,803	1	Regulator Location	Automation - Regulator Controllers	WAKESHMA Township	Customers Impacted	150
151	Grid Automation	REG26_WAKESHMA_LEONIDAS	$71,606	2	Regulator Location	Automation - Regulator Controllers	LEONIDAS Township	Customers Impacted	207
152	Grid Automation	REG26_WEBB ROAD_HALE	$35,803	1	Regulator Location	Automation - Regulator Controllers	PLAINFIELD Township	Customers Impacted	104
153	Grid Automation	REG26_WEBSTER_COLDWATER	$35,803	1	Regulator Location	Automation - Regulator Controllers	MT MORRIS Township	Customers Impacted	113
154	Grid Automation	REG26_WEST MAIN_CURWOOD	$35,803	1	Regulator Location	Automation - Regulator Controllers	MIDDLEBURY Township	Customers Impacted	267
155	Grid Automation	REG26_WILDER_WILDER	$35,803	1	Regulator Location	Automation - Regulator Controllers	ECKFORD Township	Customers Impacted	164
156	Grid Automation	REG26_WOODWARD_PLEASANT LAKE	$107,409	3	Regulator Location	Automation - Regulator Controllers	HARING Township	Customers Impacted	327
157	Grid Automation	REG26_WOODWARD_WOODWARD LAKE	$143,212	4	Regulator Location	Automation - Regulator Controllers	BOON Township	Customers Impacted	596
158	Grid Automation	REG26_WURTSMITH_MISSION	$35,803	1	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	216
159	Grid Automation	REG26_YORKVILLE_BATVIEW	$35,803	1	Regulator Location	Automation - Regulator Controllers	RICHLAND Township	Customers Impacted	157
160	Grid Automation	REG26_YORKVILLE_HIGHLAND PARK	$35,803	1	Regulator Location	Automation - Regulator Controllers	PRAIRIEVILLE Township	Customers Impacted	292
			$10,526,082	**294**					

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-143 (SAM-2)
Page: 1 of 1
Witness: SAMcPhail
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2026-2027 Test Year Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
1	Grid Automation	REG26_AGNEW_WEYBURN	$35,803	1	Regulator Location	Automation - Regulator Controllers	GRAND HAVEN Township	Customers Impacted	1337
2	Grid Automation	REG26_ALLENDALE_RIVER	$35,803	1	Regulator Location	Automation - Regulator Controllers	CASCADE Township	Customers Impacted	434
3	Grid Automation	REG26_ATLAS_GALE	$35,803	1	Regulator Location	Automation - Regulator Controllers	ATLAS Township	Customers Impacted	1052
4	Grid Automation	REG26_AUBURN_ELEVATOR	$35,803	1	Regulator Location	Automation - Regulator Controllers	WILLIAMS Township	Customers Impacted	465
5	Grid Automation	REG26_BATH_BATH	$35,803	1	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	187
6	Grid Automation	REG26_BEAVERTON_TOBACCO	$35,803	1	Regulator Location	Automation - Regulator Controllers	BUCKEYE Township	Customers Impacted	186
7	Grid Automation	REG26_BEERS_SHARP	$35,803	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	186
8	Grid Automation	REG26_BIRCH RUN_BIRCH RUN	$35,803	1	Regulator Location	Automation - Regulator Controllers	BIRCH RUN Township	Customers Impacted	96
9	Grid Automation	REG26_BRIDGEPORT_DIXIE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BRIDGEPORT Township	Customers Impacted	140
10	Grid Automation	REG26_CALKINS_BEECHER ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	648
11	Grid Automation	REG26_CALKINS_FLUSHING ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	557
12	Grid Automation	REG26_CAMELOT LAKE_COLEMAN	$35,803	1	Regulator Location	Automation - Regulator Controllers	BEAVERTON Township	Customers Impacted	119
13	Grid Automation	REG26_CARROLLTON_MAPLE RIDGE	$35,803	1	Regulator Location	Automation - Regulator Controllers	CARROLLTON Township	Customers Impacted	487
14	Grid Automation	REG26_CENTER ROAD_EVERGREEN	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT	Customers Impacted	103
15	Grid Automation	REG26_CHESANING_OAKLEY	$71,606	2	Regulator Location	Automation - Regulator Controllers	RUSH Township	Customers Impacted	687
16	Grid Automation	REG26_CHESANING_PEET	$71,606	2	Regulator Location	Automation - Regulator Controllers	ALBEE Township	Customers Impacted	291
17	Grid Automation	REG26_CLARE_FARWELL	$35,803	1	Regulator Location	Automation - Regulator Controllers	VERNON Township	Customers Impacted	229
19	Grid Automation	REG26_CLIO_MILL STREET	$107,409	3	Regulator Location	Automation - Regulator Controllers	VIENNA Township	Customers Impacted	534
20	Grid Automation	REG26_COOPER_COOPER CENTER	$71,606	2	Regulator Location	Automation - Regulator Controllers	COOPER Township	Customers Impacted	175
21	Grid Automation	REG26_COOPER_NAGEL	$35,803	1	Regulator Location	Automation - Regulator Controllers	COOPER Township	Customers Impacted	74
22	Grid Automation	REG26_COTTAGE GROVE_PREVO	$35,803	1	Regulator Location	Automation - Regulator Controllers	KAWKAWLIN Township	Customers Impacted	374
23	Grid Automation	REG26_CURTIS_MAGRUDDER	$35,803	1	Regulator Location	Automation - Regulator Controllers	TOBACCO Township	Customers Impacted	21
24	Grid Automation	REG26_DAVENPORT_CONGRESS	$35,803	1	Regulator Location	Automation - Regulator Controllers	CARROLLTON Township	Customers Impacted	1226
25	Grid Automation	REG26_DIXIE_BRANCH ROAD	$71,606	2	Regulator Location	Automation - Regulator Controllers	GENESEE Township	Customers Impacted	710
26	Grid Automation	REG26_DUFFIELD_DUFFIELD	$35,803	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	78
27	Grid Automation	REG26_DURAND_CITY	$35,803	1	Regulator Location	Automation - Regulator Controllers	OGDEN Township	Customers Impacted	600
28	Grid Automation	REG26_DURAND_GAINES	$35,803	1	Regulator Location	Automation - Regulator Controllers	BYRON Township	Customers Impacted	102
29	Grid Automation	REG26_EAST GENESEE AVE_OUTER DRIVE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BUENA VISTA Township	Customers Impacted	15
30	Grid Automation	REG26_EAST GRANT_MUD FLAT	$35,803	1	Regulator Location	Automation - Regulator Controllers	ENSLEY Township	Customers Impacted	156
31	Grid Automation	REG26_ELLIS_LAKES MALL	$35,803	1	Regulator Location	Automation - Regulator Controllers	FRUITPORT Township	Customers Impacted	215
32	Grid Automation	REG26_ELSIE_BANNISTER	$71,606	2	Regulator Location	Automation - Regulator Controllers	RUSH Township	Customers Impacted	121
33	Grid Automation	REG26_FAIRFIELD_JASPER	$35,803	1	Regulator Location	Automation - Regulator Controllers	MADISON Township	Customers Impacted	43
34	Grid Automation	REG26_FISH LAKE_ROSE	$35,803	1	Regulator Location	Automation - Regulator Controllers	ROSE Township	Customers Impacted	684
35	Grid Automation	REG26_FOURTEENTH STREET_LIBERTY STREET	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT	Customers Impacted	1424
36	Grid Automation	REG26_FOURTEENTH STREET_LIPPINCOTT STREET	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT	Customers Impacted	840
37	Grid Automation	REG26_GIRARD_DAYBURG ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	COLDWATER Township	Customers Impacted	128
38	Grid Automation	REG26_GREGORY_UNADILLA	$35,803	1	Regulator Location	Automation - Regulator Controllers	UNADILLA Township	Customers Impacted	137
39	Grid Automation	REG26_GULL LAKE_TURNER	$35,803	1	Regulator Location	Automation - Regulator Controllers	BARRY Township	Customers Impacted	100
40	Grid Automation	REG26_HENDERSHOT_CENTENNIAL	$35,803	1	Regulator Location	Automation - Regulator Controllers	RAISIN Township	Customers Impacted	14
41	Grid Automation	REG26_HESPERIA_RURAL	$35,803	1	Regulator Location	Automation - Regulator Controllers	SEVILLE Township	Customers Impacted	505
43	Grid Automation	REG26_HILL ROAD_WALKABOUT	$35,803	1	Regulator Location	Automation - Regulator Controllers	MUNDY Township	Customers Impacted	357
44	Grid Automation	REG26_HOGAN ROAD_HOISINGTON	$35,803	1	Regulator Location	Automation - Regulator Controllers	FENTON Township	Customers Impacted	265
45	Grid Automation	REG26_HOLTON_HOLTON	$35,803	1	Regulator Location	Automation - Regulator Controllers	HOLTON Township	Customers Impacted	404
46	Grid Automation	REG26_HUBBARDSTON ROAD_STONEY CREEK	$35,803	1	Regulator Location	Automation - Regulator Controllers	DALLAS Township	Customers Impacted	63
47	Grid Automation	REG26_KAWKAWLIN_LAGOON BEACH	$35,803	1	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	876
48	Grid Automation	REG26_KAWKAWLIN_WHEELER ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	176
49	Grid Automation	REG26_KNIGHT_ROSEMARY	$35,803	1	Regulator Location	Automation - Regulator Controllers	PORTSMOUTH Township	Customers Impacted	1494
50	Grid Automation	REG26_LAINGSBURG_LELAND ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	VICTOR Township	Customers Impacted	209
51	Grid Automation	REG26_LARKIN_N MIDLAND	$35,803	1	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	621
52	Grid Automation	REG26_LEHRING_COLE ROAD	$71,606	2	Regulator Location	Automation - Regulator Controllers	BURNS Township	Customers Impacted	251
53	Grid Automation	REG26_LEHRING_MYERS LAKE	$214,818	6	Regulator Location	Automation - Regulator Controllers	ARGENTINE Township	Customers Impacted	933
54	Grid Automation	REG26_LENNON ROAD_SHOPPERS	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	238
55	Grid Automation	REG26_LESLIE_BUSINESS	$35,803	1	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	145
56	Grid Automation	REG26_LEVELY_ALLBRIGHT	$35,803	1	Regulator Location	Automation - Regulator Controllers	BUCKEYE Township	Customers Impacted	311
57	Grid Automation	REG26_LEVELY_STURGEON	$143,212	4	Regulator Location	Automation - Regulator Controllers	TOBACCO Township	Customers Impacted	655
58	Grid Automation	REG26_LINDEN_NORTH LINDEN	$35,803	1	Regulator Location	Automation - Regulator Controllers	FENTON Township	Customers Impacted	782
59	Grid Automation	REG26_LITCHFIELD_QUAKER LAKE	$35,803	1	Regulator Location	Automation - Regulator Controllers	CLARENDON Township	Customers Impacted	56
60	Grid Automation	REG26_MAGNUS_MCKAY FARM	$107,409	3	Regulator Location	Automation - Regulator Controllers	SURREY Township	Customers Impacted	519
61	Grid Automation	REG26_MCCANDLISH_THREAD RIVER	$35,803	1	Regulator Location	Automation - Regulator Controllers	ATLAS Township	Customers Impacted	257
62	Grid Automation	REG26_MCGRAW_PORTSMOUTH	$35,803	1	Regulator Location	Automation - Regulator Controllers	PORTSMOUTH Township	Customers Impacted	556
63	Grid Automation	REG26_MONTROSE_MCKINLEY ROAD	$71,606	2	Regulator Location	Automation - Regulator Controllers	VIENNA Township	Customers Impacted	383
64	Grid Automation	REG26_MORRICE_M-78	$35,803	1	Regulator Location	Automation - Regulator Controllers	ONEIDA Township	Customers Impacted	166
65	Grid Automation	REG26_MORRICE_SOUTH MORRICE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BURNS Township	Customers Impacted	347
66	Grid Automation	REG26_MT FOREST_BENTLEY	$179,015	5	Regulator Location	Automation - Regulator Controllers	GRIM Township	Customers Impacted	553
67	Grid Automation	REG26_MT FOREST_MT FOREST	$143,212	4	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	496
68	Grid Automation	REG26_NEFF ROAD_DODGE ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	VIENNA Township	Customers Impacted	232
69	Grid Automation	REG26_NESTROM_SCENIC DRIVE	$71,606	2	Regulator Location	Automation - Regulator Controllers	LAKETON Township	Customers Impacted	863
70	Grid Automation	REG26_NEW HAVEN_JUDDVILLE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BRADY Township	Customers Impacted	370
71	Grid Automation	REG26_NEW LOTHROP_BYRON ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	MAPLE GROVE Township	Customers Impacted	60
72	Grid Automation	REG26_NEW LOTHROP_REED ROAD	$71,606	2	Regulator Location	Automation - Regulator Controllers	MAPLE GROVE Township	Customers Impacted	148
73	Grid Automation	REG26_NORTH MUSKEGON_STATE PARK	$71,606	2	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	860
74	Grid Automation	REG26_OAK STREET_COOPER STREET	$35,803	1	Regulator Location	Automation - Regulator Controllers	BLACKMAN Township	Customers Impacted	106
75	Grid Automation	REG26_OSHTEMO_ALMENA	$35,803	1	Regulator Location	Automation - Regulator Controllers	OSHTEMO Township	Customers Impacted	567
76	Grid Automation	REG26_OTISVILLE_IRISH ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	FOREST Township	Customers Impacted	98
77	Grid Automation	REG26_OTISVILLE_STATE ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	FOREST Township	Customers Impacted	191
78	Grid Automation	REG26_OWOSSO_GOULD	$35,803	1	Regulator Location	Automation - Regulator Controllers	CALEDONIA Township	Customers Impacted	717
79	Grid Automation	REG26_PINCONNING_WHITE FEATHER	$71,606	2	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	95
80	Grid Automation	REG26_PORTAGE_SHAVER ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	SCHOOLCRAFT Township	Customers Impacted	1183
81	Grid Automation	REG26_PORTER_PARTS	$35,803	1	Regulator Location	Automation - Regulator Controllers	GRAND BLANC Township	Customers Impacted	318
82	Grid Automation	REG26_PRICE ROAD_PRICE	$35,803	1	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	257
83	Grid Automation	REG26_RAVENNA_MOORLAND	$35,803	1	Regulator Location	Automation - Regulator Controllers	RAVENNA Township	Customers Impacted	420
84	Grid Automation	REG26_RIDGEVIEW_RIVER OAKS	$35,803	1	Regulator Location	Automation - Regulator Controllers	COMSTOCK Township	Customers Impacted	5
85	Grid Automation	REG26_ROTHBURY_NEW ERA	$35,803	1	Regulator Location	Automation - Regulator Controllers	BENONA Township	Customers Impacted	465
86	Grid Automation	REG26_RUSSELLVILLE_RICHFIELD	$35,803	1	Regulator Location	Automation - Regulator Controllers	RICHFIELD Township	Customers Impacted	305
87	Grid Automation	REG26_RUSSELLVILLE_VASSAR ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	GENESEE Township	Customers Impacted	152
88	Grid Automation	REG26_RUSSELLVILLE_VICTORIA	$71,606	2	Regulator Location	Automation - Regulator Controllers	RICHFIELD Township	Customers Impacted	1025
89	Grid Automation	REG26_SALZBURG_SALZBURG	$71,606	2	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	128
90	Grid Automation	REG26_SCIPIO_MOSHERVILLE	$35,803	1	Regulator Location	Automation - Regulator Controllers	SCIPIO Township	Customers Impacted	89
91	Grid Automation	REG26_SEVEN MILE_MAIDA	$35,803	1	Regulator Location	Automation - Regulator Controllers	PINCONNING Township	Customers Impacted	70
92	Grid Automation	REG26_SEVEN MILE_QUARTERLINE	$35,803	1	Regulator Location	Automation - Regulator Controllers	BROOKS Township	Customers Impacted	113
93	Grid Automation	REG26_SKYLARK_HILL	$71,606	2	Regulator Location	Automation - Regulator Controllers	GRAND BLANC Township	Customers Impacted	979
94	Grid Automation	REG26_SKYLARK_ROCKING CHAIR	$35,803	1	Regulator Location	Automation - Regulator Controllers	GRAND BLANC Township	Customers Impacted	997
95	Grid Automation	REG26_SKYLARK_SUN VALLEY	$35,803	1	Regulator Location	Automation - Regulator Controllers	ATLAS Township	Customers Impacted	1016
96	Grid Automation	REG26_SPRING ARBOR_CHAPEL	$35,803	1	Regulator Location	Automation - Regulator Controllers	SPRING ARBOR Township	Customers Impacted	122
97	Grid Automation	REG26_SPRING DRIVE_BISHOP LAKE	$35,803	1	Regulator Location	Automation - Regulator Controllers	SHERMAN Township	Customers Impacted	825
98	Grid Automation	REG26_SQUIRE HILL_EDGEWATER	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	1230
99	Grid Automation	REG26_SQUIRE HILL_HILLSIDE	$35,803	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	137
100	Grid Automation	REG26_ST CHARLES_FERGUS	$35,803	1	Regulator Location	Automation - Regulator Controllers	ALBEE Township	Customers Impacted	116
101	Grid Automation	REG26_STEEL DRIVE_VISTA	$35,803	1	Regulator Location	Automation - Regulator Controllers	TYRONE Township	Customers Impacted	663
102	Grid Automation	REG26_SWARTZ CREEK_MORRISH ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	1003
103	Grid Automation	REG26_THOMAS_THOMAS	$35,803	1	Regulator Location	Automation - Regulator Controllers	THOMAS Township	Customers Impacted	79
104	Grid Automation	REG26_TINSMAN_FISH LAKE ROAD	$35,803	1	Regulator Location	Automation - Regulator Controllers	HOLLY Township	Customers Impacted	118
105	Grid Automation	REG26_TOWN LINE_FRASER	$35,803	1	Regulator Location	Automation - Regulator Controllers	MONITOR Township	Customers Impacted	248
106	Grid Automation	REG26_TOWN LINE_MACKINAW	$35,803	1	Regulator Location	Automation - Regulator Controllers	KAWKAWLIN Township	Customers Impacted	57
107	Grid Automation	REG26_WALDO_LABORATORY	$35,803	1	Regulator Location	Automation - Regulator Controllers	DEWITT Township	Customers Impacted	834
108	Grid Automation	REG26_WAMPLERS_FRANKLIN	$35,803	1	Regulator Location	Automation - Regulator Controllers	MANCHESTER Township	Customers Impacted	241
109	Grid Automation	REG26_WARNER_MILO	$35,803	1	Regulator Location	Automation - Regulator Controllers	PRAIRIEVILLE Township	Customers Impacted	838
110	Grid Automation	REG26_WHITE CLOUD_WILLIAM STREET	$35,803	1	Regulator Location	Automation - Regulator Controllers	SHERMAN Township	Customers Impacted	277
111	Grid Automation	REG26_WINGATE_NORTH	$35,803	1	Regulator Location	Automation - Regulator Controllers	FREEDOM Township	Customers Impacted	177
112	Grid Automation	REG26_WINGATE_SOUTH	$35,803	1	Regulator Location	Automation - Regulator Controllers	JOHNSTOWN Township	Customers Impacted	162
			$5,119,829	**143**					

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Line Sensor Reliability Benefits

Case No.: U-21870
Exhibit No.: A-144 (SAM-3)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**10,884,341**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions		
# of LVD primary outages a year	**13901**	**Primary outages refers to outages that occur on the lines between the transmission substations before transformer**
Probability of Outage Occurance on LVD circuit with Line Sensors	**67%**	**Chance of outage occuring on circuit with line sensors**
The likelihood of fault location being able to be utilized for a given outage is not reported.	**77%**	**Probability of sensors offline, sometimes other issues fault is not reported, branch of circuit not covered.**
# minutes patrol time savings per outage	**10**	**Time saved if line sensor is used.**
Average # of customers on a primary outage	**151**	**Average number of customers on primary outage**
# of CE Customers System wide	**1,889,301**	
Sensors Installed per Year Past 2025	**100**	**Assume past 2025, installs 100 sensors/year**
Benefits Calculations		
Annual total # of minutes saved systemwide (CMI)	**10,884,341**	

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

RAMP Reliability Benefits

Case No.: U-21870
Exhibit No.: A-145 (SAM-4)
Page: 1 of 3
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**2,466,699**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

# of CE Customers System wide	1889301
CE SAIDI Minutes (excluding MEDS)	155
# of Line Sensors Installed per Year	500

Line Sensors Scaled Up over time

2025	3000
2026	3500
2027	4000
2028	4500
2029	5000

Assume that the crew spends an additional amount of time to find the anomaly during an emergent outage condition without recourse to RAMP but with the potential use of Line Sensors and meters. Assume that additional amount of time is 10% on average.

	CMI Projected Savings increased by 10% during emergent outage conditions	Total # of additional Outage Minutes per Year
2025	407005	37000
2026	474840	43167
2027	542674	49334
2028	610508	55501
2029	678342	61667

Projected # of Customer Minutes Interupted (CMI) Realized plus a Percentage of UnRealized

	CMI Projected Realized Savings (Avoided)
2025	370005
2026	431672
2027	493340
2028	555007
2029	616675

Benefits Calculations

	SAIDI
2025	0.196
2026	0.228
2027	0.261
2028	0.294
2029	0.326

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

RAMP Reliability Benefits

Case No.: U-21870
Exhibit No.: A-145 (SAM-4)
Page: 3 of 3
Witness: SAMcPhail
Date: June 2025

Line No.		(a) Aug-Dec 22	(b) 2023	(c) Jan-July 24	(d) Aug24-Dec24	Sum	
1	CMI	136998	147488	112332	68620		
2	SAIDI	0.072871277	0.078451064	0.059751064	0.0365		
3	Sensor count	930	1950	2457	2457		
4	Months	5	12	7	5	29	
5	SAIDI/Sensor/Month	1.56712E-05	3.35261E-06	3.4741E-06	2.9711E-06		
6	Average	2.70194E-06	1.38729E-06	8.38576E-07	5.12259E-07	5.44006E-06	
7	SAIDI/Sensor/Year					**6.52807E-05**	

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Line Regulator Controller Upgrades BCA Methodology

Case No.: U-21870
Exhibit No.: A-146 (SAM-5)
Page: 1 of 3
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Total Benefits**	**$23,606,493**	
2	**Total Reliability Benefits**	**56,625**	**Avoided CMI**
3	**Total Costs**	**$15,129,138**	
4	**NPV**	**$8,477,355**	

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

Reductions in Distribution (Labor & Material)

Savings due to a reduction in Routine Truck Rolls		
	$500	Routine Truck Rolls are saved because all Line Regulator Controls can be manipulated remotely in lieu of having to send personnel there to make voltage adjustments
System Population	1,889,301	
Average # of hours for Routine Work	1	
# of LVD Line Regulator Locations	1800	
Percentage of LVD Circuits that require adjustments to Line Voltage Regulators over the course of a Year	10%	It can be assumed that 10% of all Line Regulator Locations experience voltage adjustments over a 10 year period on average
# of LVD Line Regulator Locations Requiring Adjustments each Year	180	
Annual Average Savings due to Routine Truck Rolls	$90,000	
Reg Material & Labor Savings due to Life Extension for Regulator Tanks		
Average Regulator Tank Cost	$20,000	About 50 Reg Tank replacements take place on average in any given year across the LVD Fleet. Over a ten year period about 500 Regulator Tank replacements will be necessary to restore full functionality to LVD Line Regulator Locations. Regulator Tanks Useful life spans will be extended due to the preventative maintenance tapping feature which has been turned on for all new replacement Regulator Controls. It is reasonable to assume that annual Regulator Tank Replacement will be reduced by at least 25% on an annual basis due to this preventative maintenance function over a ten year period.
Annual Reduction in # of Tank Replacements	12.5	
Storeroom Loadings Factor	2.3	
Average # of Regulator Tank Replacement per Year	50	
Average # of CE Crew Manhours for a Typical Tank Replacement	8	Includes EFL Support functions including replacement of failed tanks at the specific location
CE Crew Hourly Rate (Loaded)	$440	
Average # of EFL Manhours for a Typical Tank Replacement	2.5	Includes Line Regulator Control Operation and Wiring Activities
EFL Hourly Rate (Loaded)	$110	
Total Average Annual Cost Labor Savings	$47,438	
Average Material Savings per Year due to Reg Tank Life Extension	$622,438	
Cellular Cost Savings due to Modem Configurations		
$7.00 per Month (250mb per month per device) based on Actual Data Usage from IT for a sample of Scada enabled Reg Devices	$7	
~900 Multiphase Pole Locations (3 phase)	900	
~340 Multiphase Pole Locations (2 phase)	340	
Annual Cellular Cost for a Single Phase Control 3 phase location	$226,800	
Annual Cellular Cost for a Single Phase Control 2 phase location	$57,120	
Annual Cellular Cost for a Multiphase Control 3 phase location	$75,600	
Annual Cellular Cost for a Multiphase Control 2 phase location	$28,560	
Annual Cellular Savings for a Multiphase Control 3 phase location	$151,200	
Annual Cellular Savinos for a Multiphase Control 2 phase location	$28,560	
Full deployment starts in 2027 so full value of Cellular savings starts in the year 2027		
% Complete Deployment after 2024	75.33%	
% Complete Deployment after 2025	87.56%	
Total Annual Cellular Savings@100%	$179,760	
Reg Material Avoided Costs due to Replacement of Line Regulator Controls		Because Line Regulator Controls have been replaced across the fleet with all new Controls that have a 10 year Warranty at about 1800 locations across the fleet, a significant amount of costs to replace these controls has been avoided for the next ten years. Conservatively, we can assume that about 10% of these controls would have failed each year starting with the year 2027. In addition, we know that without the execution of this project these controls would have been replaced with Single Phase Controls paired with their corresponding tanks. This substantial cost in future years has been AVOIDED due to the executon of the project.
# of Multiphase Controls Installed 3 Phase Locations	900	
# of Single Phase Controls Replaced at Multiphase Locations	2700	
# of Multiphase Controls Installed 2 Phase Locations	350	
# of Single Phase Controls Replaced at 2 Phase Multiphase Locations	700	
# of Single Phase Controls Replaced at Single Phase locations	1000	
TOTAL # of Single Phase Controls Replaced during the Project	4400	
Average Cost of a Single Phase Control over the next 10 years considering 5% inflation over those years	$7,000	
Current Cost of a Single Phase Reg Control	$6,400	
Average Lifespan of a Regulator Control	20 to 25 years	Reference: Regulator Control Supplier
Total Estimated # of Controls that will fail during a Time Period starting in the year 2027 for the next ten years.		Large Sample Size of 790 were evaluated. Of that sample size 163 were year 2000 or older (pre-2000) representing about 20% overall. So, an extrapolation across the entire population of 4400 Controls results in about 4400 *20% or about 880 Controls that are likely to fail durng the 10 year period starting in 2027
Estimated # of Controls that were likely to fail during the time period after completion of the project starting in 2027 over a ten year period	800	
Apply Loading factor of 2.3 assuming these Controls would have been from Stores.	2.3	
Average Annual Rate of Replacement for Reg Controls starting in 2027	10%	
Average Annual Reg Control Replacement Costs starting in 2027	$1,288,000	

Customer Savings (MWh)

Reg-enabled MW Peak Reduction Benefits (MWh)		
Cost/MWh ($)	$32.15	
# of Circuits with CVR (as of 12/31/2024):	439	
2030 # of Circuits	900	
# of CVR circuits with Line Regs:	73	
# of Line Regs supporting CVR:	42	
# of available line regs on CVR circuits:	211	
% of CVR-enabled line regs:	20%	
Expected MWh savings of CVR through 2030 (MWh):	271582	
% of CVR-enabled line regs vs. # of line regs on LVD system:	2%	
Assume 2% support of line regs for expected MWh savings (MWh):	6336.91	Total MWh savings through 2030 (NOT per year)
Assume 2% support of line regs for expected Cost/MWh savings ($):	$203,731.76	Total $ savings through 2030 (NOT per year)
Average Annual Benefit for expected Cost/MWh savings ($):	$18,521.07	

CMI

# of Customers Fleetwide	1,889,301	
Average Length of a Line Regulator Caused Outage (Minutes)	30	
Average # of Customers on an LVD Circuit Outage	151	
Annual Average # of Outages Avoided due to Automatic Preventative Maintenance is equal to the # of Reg Tank Replacements that do not have to happen in a year	13	
Total Average Custimer Minutes Interrupted (CMI) Saved on an Annual Basis	56625	

Benefits Calculations

Monetized Benefits:		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
$ 1,080,000	Avoided Truck Roll Savings	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000
$ 7,469,250	Material Savings due to Life Extension	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438
$ 222,253	Reg Enabled CVR Benefits	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521
$ 1,954,990	Cellular Cost Savings due to Modem Configurations	$0.00	$157,389.87	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760
$ 12,880,000	Material Savings due to Failed Reg Controls	$0	$0	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000

Costs Calculations

Assumptions

Post-Tax WACC (%): 7.25%

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capital Spend ($):	$ 15,129,138	$ 8,000,000	$ 7,646,000										

The manufacturers date was recorded from the nameplate on the 790 regulator tanks during line regulator deployment activities
This is considered to be a large sample size against a total population of 1800 locations

The large sample size of 790 were evaluated. Of that sample size 163 were year 2000 or older (pre-2000) representing about 20% overall. So, an extrapolation across the entire population of 4000 controls results in about 4000 *20% or about 800 controls that are likely to fail during the 10 year period starting in 2027 based on average lifespan of 20 to 25 years for a regulator control

Here are the numbers associated with the 163 that were year 2000 or older

Time Span	# of Controls
Pre-1990	1
1990-1995	49
1996-2000	113
2001-2005	116
2006-2010	171
2006	35
Other (Remainder)	450
	340
Total Sample Size	790

Consequently, a total of 163 are the year 2000 or older (pre-2000) or about 20% of the total sample size.
163

% of Sample Size 2000 year or older versus the total Sample Size **20.63%**

So this large sample size is likely representative of the total population and we can extrapolate across the entire populuation to determine the age composition of controls across the LVD fleet.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
NOVA TS Comms Reliability Benefits

Case No.: U-21870
Exhibit No.: A-147 (SAM-6)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**3,256,577**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

1,889,301 System Population (number of customers)

Benefits Calculations

# of outages yearly	average customer count per incident	number of NTS
33	372	375

<- From historic outage data per device type

Per Device	remote operation reduction (min)	outage response and HLT reduction (min)
Per each event	15	25
Customer minutes per year	491	818

<- estimated duration savings based on operations insight

CMI	SAIDI
1309	0.00069

	2025	2026	2027	2028	2029	2030	2031	2032	2033
SAIDI	0.002	0.071	0.141	0.210	0.260	0.260	0.260	0.260	0.260

Savings from outage time reduction

minutes saved per outage	40
average minutes per year	3.52

Note: deployment beyond 2025 funded by LVD Reliability

Timeline	**2025**	**2026**	**2927**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Unit Forecast	3	100	100	100	72				
Total Units	3	103	203	303	375	375	375	375	375

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer-Peer Schemes Reliability Benefits

Case No.: U-21870
Exhibit No.: A-148 (SAM-7)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**184,739,600**	Avoided CMI

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

System Population (number of customers) 1,889,301

Benefits Calculations

Step 4: project at Scale Impacts

Timeline	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ATR Loop Forecast	-	1	15	15	15	15	15	-	-	-	-	-
Resilience/Reliability												
Avoided Outage Costs for Customers (SAIDI)	0.00	0.16	2.56	4.96	7.36	9.76	12.16	12.16	12.16	12.16	12.16	12.16

SAIDI benefit per regular ATR loop	0.11	assumes 200 CAIDI average duration times average 3217 outages saved per loop per 3 years based on historical ATR performance
SAIDI benefit increase from restricted loops	141%	oneway, load limited, and mutually exclusive avoided downtime
SAIDI benefit increase from fewer customers affected	133%	sectionalizing benefit factor due to smaller zones affected
average incremental SAIDI improvement per loop	0.100	

avoided outage costs - customer

Incremental ATR SAIDI Calcs (w/ ME

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Sum	-	**0.1600**	**2.4005**	**2.4005**	**2.4005**	**2.4005**	**2.4005**	-	-	-	-	-

	devices	zones
normal	2.5	4.5
extra ATRs proposed	4	6

	probability of occurrence	effect on benefits (1.0 is perfect unaffected)		
Load Limit	0.173	0.873873874		
	appropriate	0.703	0.961538462	2 weeks offline when triggers
	excessive	0.297	0.666666667	4 months offline proactively
				we are assuming that there are legitamate days which the loop can't transfer, and those happen for P-P too and are a wash. These are deeper cuts into the benefits due to proactively shutting down the loop.
Mutually Exclusive	0.200	0.625		
		0.5	only one of two loops can operate at a time	
		0.5	limited transfers (half of time)	6/12 months conservatively cannot run both, but the other 6 months on average can
		1	non-limited transfers (half of time)	this means even other non-capacity-limited transfers can occur all year too that would have been missed
One Way	0.213	0.625		
		0.5	half of the loop has no benefit by definition	
		0.8	probability that a loop has the topographical capability to be two way	

Hours

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Sum	0.00	10.08	151.14	151.14	151.14	151.14	151.14	0.00	0.00	0.00	0.00	0.00

# of Loops	180	Load Limited	79
		ME Limited	34
		Total LL & ME	**113**
		rules per loop:	**0.628**

		average hours per rule
	Planning	
	Evaluating for LL	1.00
	Evaluating ME loops that are fed by sam	0.50
	Evaluating how many days a loop goes (	0.50
	Gathering SCADA keys	0.50
	Maintining the LL Power App	0.50
	Email & meetings regarding LL	2.00
	Re-evaluating LL	0.75
	training intern to review LL	0.30
	Total	**6.05**
building	Grid Apps	3.00
reviewing/approving	DCC	4.00
preparing	Operations Engineering	1.00
		times per year a rule activates on average: 1
reacting to triggered rule	DCC	1.00
reacting to triggered rule	Operations Engineering	1.00

Timeline	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Peer-peer Deployment Forecast	76	0	1	15	15	15	15	15	0	0	0	0	0

average number of ATRs (non-Tie) in a regular loop	2.5	from actual ATR per loop count average
average number of ATRs (non-Tie) in a P-P network	4	2.5 is no extra sectionalizing, more is increased sectionalizing
number of Tie ATRs above a regular loop	1	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recloser Modernization Reliability Benefits

Case No.: U-21870
Exhibit No.: A-149 (SAM-8)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**89,841,549**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

System Population (number of customers)	1,889,301	
patrol time savings due to fault location	10	min

Benefits Calculations

Reduced Patrol Time SAIDI

		Reducing patrol time remote operation reduction (min)	Reducing re-energization time outage response and HLT reduction (min)	
Per Device	Per each event	10	35	
	Customer minutes per year			
	incidents per year		0.572	multiply that by how many outages happen on a recloser each year
	customers per incident		123	average customers per incident
			3160	CMI

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SAIDI	-	0.008	0.343	1.179	2.517	4.190	5.863	6.691	6.691	6.691	6.691	6.691

Timeline		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Deployment Forecast	4000	0	5	200	500	800	1000	1000	495

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Supplemental Line Sensors Reliability Benefits

Case No.: U-21870
Exhibit No.: A-150 (SAM-9)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**13,751,914**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

patrol time saved by having line sensors on a circuit for fault location **10** **minutes**

300	**average number of customers affected during a non-secondary outage**
1889301	**system population**
80%	**percent of SAIDI due to LVD system**
8	**Reliability SAIDI savings 2024**

Benefits Calculations

Fault Location - On circuits that previuosly had conductor compatability issues

New Circuits due to conductor size/type limitations:

13901	non-secondary outages per year from historic outage data
80%	chance of having a circuit with line sensors on it
15%	incremental circuit coverage for lines sensors
2085	number of outages affected by having extra circuits covered with sensors
85%	likelihood of fault location being able to be utilized for a given outage
10	minutes patrol time savings per outage
151	average number of customers on a non-secondary outage
2676290	annual minutes saved total systemwide once additional circuits are implemented over the remaining 350+ circuits that don't have sensors due to conductor issues.
1.42	**SAIDI saved**
0.00069	**SAIDI saved per sensor**

		2025	2026	2027	2028	2029	2030	2031	2032	2033
SAIDI	**Sum**	-	0.008	0.077	0.420	1.107	1.417	1.417	1.417	1.417

Sensors deployed on the system

existing	proposed
11,000	**2,063**
80%	15%

Timeline		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Sensor Deployment Forecast	2063	0	12	100	500	1000	451				

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Metro Modernization Reliability Benefits

Case No.: U-21870
Exhibit No.: A-151 (SAM-10)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**1,062,438**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

1889301	**customer population**
60	**average time to visit a site with a crew going into enclosed spaces**
157	**number of vaults today**

Benefits Calculations

Reduce patrol time via not having to check so many device locations in manholes to **validate the state of the system** and location of the fault.

5	average number of switching and tagging points during an incident to validate
60	average length of time to validate a site
300	minutes to validate the state of the system before restoration
30	projected validation minutes in new state
270	minutes of validation saved
1561	customer affected annually
421470	saved customer minutes
0.222	**SAIDI**
0.0014	SAIDI per vault

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SAIDI	**Sum**	0.0000	0.0028	0.0099	0.0170	0.0240	0.0311	0.0381	0.0452	0.0523	0.0593	0.0664	0.0735

Remote Restoration

this is at the end of each outage incident that we can avoid returning to the open vault/circuit situation because it can be closed in remotely.

1,561	customer affected annually
60	average time it takes to set up for restoration which is being eliminated
93,660	annual minutes saved due to remote restoration
596.56	minutes saved per vault

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SAIDI	**Sum**	0.0000	0.0006	0.0022	0.0038	0.0054	0.0069	0.0085	0.0101	0.0117	0.0133	0.0148	0.0164

Planned Transfers < instead of sending crews to multiple vaults, execute return to normal switching steps remotely without crew involvement

5	average number of switching and tagging points in a switching order
60	average length of time to validate a site
50	number of switching orders executed in a year
15	time it takes in new state
237.5	saved crew hours per switching order

Public safety/security:

high water alarms to avoid flooding vaults which dump all customers.

		cust	average min	custmin	
historical flooding outage data:	2024	1	87	313	27231
	2021	2	460.5		191000
	2019	3			26112
					48869 annual flooding outage minutes avoided due to high water sensors/alarms
					311 per vault

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SAIDI	0.00000	0.00033	0.00115	0.00198	0.00280	0.00362	0.00445	0.00527	0.00610	0.00692	0.00774	0.00857

Safety how many people hours of exposure is being eliminated

24	number of outage incidents in 2024
370	number of switching times a vault would be visited
15	average time at a site spent doing the hazardous work associated with entering vaults
2	average number of persons in a crew
185	total people hours of exposure to vaults by crews eliminated
1.18	people hours of exposure per vault

exposure	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
hours	0.0	2.4	8.2	14.1	20.0	25.9	31.8	37.7	43.6	49.5	55.4	61.3

Timeline	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Vault Deployment Forecast	0	2	5	5	5	5	5	5	5	5	5	5

Line No.	(a)	(b)	
1	**Total Benefits**	**$**	**18,861,196**
2	**Total Costs**	**$**	**17,378,801**
3	**NPV**	**$**	**1,482,395**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

	1,889,301	Total Electric Customers		2,295	Five Year Average of Annual Outages per feeder
$	440.00	Typical 3 person Elec Dist Crew $/hour (loaded costs)	$	357.29	Average O&M Spend per outage on Feeder
	15%	Distribution Asset Management Year to Year Improvement %		40%	Avoided Restoration Costs Loading Multiplier
	5%	Asset Data Quality Beginning Perecentage		31%	Overtime %.
	36%	Asset Management System (AMS) maturity %		105%	Maturity Cost Adder.
	3%	Asset Depreciation Improvement value		23,267	Medium & Large C&I customer count
	85%	% Work Assignned to CE Crews			
	15%	% Work Assignned to Contract Crews			
$	955.00	Contractor Crew Cost $/hour (direct cost)			

Benefits Calculations

Benefit Calculations are summarized in the "Benefits & Costs Data" worksheet.
The "Benefit Details" worksheet describes the different project impacts on the B
The "Asset Details" worksheet includes asset specific benefit cal
The "Avoided Restoration Costs" worksheet is used to show a multi-year breakdown of avoided restoration co

Monetized Benefits($): *(yearly values in thousands)*

$ 18,861,196

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Tota per Year	$ 1	$ 234	$ 839	$ 1,706	$ 2,375	$ 3,139	$ 4,151	$ 5,488	$ 6,589	$ 7,577

Costs Calculations

WACC **7.25%**

Capital Spend ($): *(yearly values in thousands)*

$ 17,378,801

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total per Year	$ 3,331	$ 2,506	$ 10,254	$ 1,804	$ 1,804	$ 400	$ 400	$ 400	$ 400	$ 400

Line No.				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Total of all Costs**			$ 3,331	$ 2,506	$ 10,254	$ 1,804	$ 1,804	$ 400	$ 400	$ 400	$ 400	$ 400
2													
3	**Asset Repository (AR)**			**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
4	Asset Count Project Scope			20	20	20	20	20	20	20	20	20	20
5	Planned Yearly Assets			7	6	6	1	0	0	0	0	0	0
6	Planned Assets Cumulative			7	13	19	20	20	20	20	20	20	20
7	Asset Percentage			35%	65%	95%	100%	100%	100%	100%	100%	100%	100%
8		Months		12	12	12	3						
9	DICE			$ 700									
10	AR Cost	IT	90	$ 1,080	$ 1,080	$ 1,080	$ 270	$ -	$ -	$ -	$ -	$ -	$ -
11	Overheads			$ 1,024	$ 324	$ 324	$ 81						
12				$ 2,804	$ 1,404	$ 1,404	$ 351						
13													
14	**Asset Performance Management (APM)**			**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
15	Asset Count Project Scope			20	20	20	20	20	20	20	20	20	20
16	Planned Yearly Assets			2	5	13	0	0	0	0	0	0	0
17	Planned Assets Cumulative			2	7	20	20	20	20	20	20	20	20
18	Asset Percentage			10%	35%	100%	100%	100%	100%	100%	100%	100%	100%
19		Months		9	12	12	12	3					
20	APM Cost	IT	45	$ 405	$ 540	$ 6,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Overheads			$ 122	$ 162	$ 1,950	$ -	$ -					
22	Total			$ 527	$ 702	$ 8,450	$ -	$ -					
23													
24	**Asset Investment Planning (AIP)**			**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
25	Asset Count Project Scope			20	20	20	20	20	20	20	20	20	20
26	Planned Yearly Assets			2	5	6	6	1	0	0	0	0	0
27	Planned Assets Cumulative			2	7	13	19	20	20	20	20	20	20
28	Asset Percentage			10%	35%	65%	95%	100%	100%	100%	100%	100%	100%
29													
30	**Device Management (DM)**			**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
31	Asset Count Project Scope			20	20	20	20	20	20	20	20	20	20
32	Planned Yearly Assets			2	5	6	6	1	0	0	0	0	0
33	Planned Assets Cumulative			2	7	13	19	20	20	20	20	20	20
34	Asset Percentage			10%	35%	65%	95%	100%	100%	100%	100%	100%	100%
35		Months		0	0	0	9	12					
36	DM Cost	IT	90	$ -	$ -	$ -	$ 810	$ 1,080	$ -	$ -	$ -	$ -	$ -
37	Overheads			$ -	$ -	$ -	$ 243	$ 324					
38	Total			$ -	$ -	$ -	$ 1,053	$ 1,404					
39													
40	**DistAM Asset Management System (AMS)**			**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
41	AMS Team				$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400

EPRI



P200C Distribution Operations

DA/FLISR Research Report

Consumers Energy

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1 SUPPORT FOR DESIGN OF DISTRIBUTION AUTOMATION / FLISR SOLUTION – STATEMENT OF WORK

Background and Objectives

Distribution Automation (DA) and Fault Location Isolation and Service Restoration (FLISR) are key components of a modern distribution system, with the primary goals of improving service reliability, enhancing resilience, providing situational awareness, and contributing to operational efficiency. The objective of this project is to collaborate with the Funder to develop a set of detailed design documents specifying all technical aspects of a DA/FLISR solution which will support their Grid Modernization goals.

Requirements Gathering and System Analysis

EPRI Subject Matter Experts will facilitate a series of virtual fact finding workshops to gather specific information about the Funder's distribution system and state of existing DA/FLISR decisions and sub-systems. These workshops will include, but are not limited to assessments of:

- Funder's substation and feeder design standards
- Funder's feeder loading and reliability planning standards
- Funders distribution protection standards
- Funder's reliability history and availability of data to optimize potential benefits
- Funder's corporate reliability / resilience goals
- Field Work Clearances/Practices related to DA/FLISR
- Funder's existing ADMS/DSCADA implementations and capabilities
- Funder's existing DA switch equipment and placement standards
- Funder's existing field area communication network implementations and capabilities
- History of any previous DA/FLISR trials or Initial Implementations and experiences from them

DA/FLISR Design Workshop and Design Documentation

EPRI Subject Matter Experts will conduct an additional series of virtual workshops to collaborate with Funder to evaluate the present state, consider the pros and cons of various options and then develop a comprehensive design and system architecture that details the following areas:

- Detailed Functional Architecture of DA/FLISR solution
- Recommendation (at the device type) for DA Switch solution
- Data requirements from SCADA, OMS, AMI, ADMS
- Design of FLISR logic, including protection sequence, FLISR sequence, Planning Constraints, Operational / Clearance Constraints, SCADA Constraints, and Hybrid logic
- High Level communications requirements
- Integration requirements for ADMS, SCADA, OMS, AMI, DERMS

DA/FLISR Program Planning and Roadmap

EPRI Subject Matter Experts will evaluate the present state of the Funder, the detailed DA/FLISR system design and architecture recommendations, DA/FLISR goals, and any existing plans to develop a detailed roadmap for the design, integration, implementation, and operation of a DA/FLISR solution. This roadmap will incorporate dependencies and desired implementation dates. Additionally a program management plan will be provided which provides guidance on activities including, but not limited to, requirements development, project team development, change management, ongoing support organization requirements, stakeholder training, benefits analysis.

DA/FLISR Test Plan

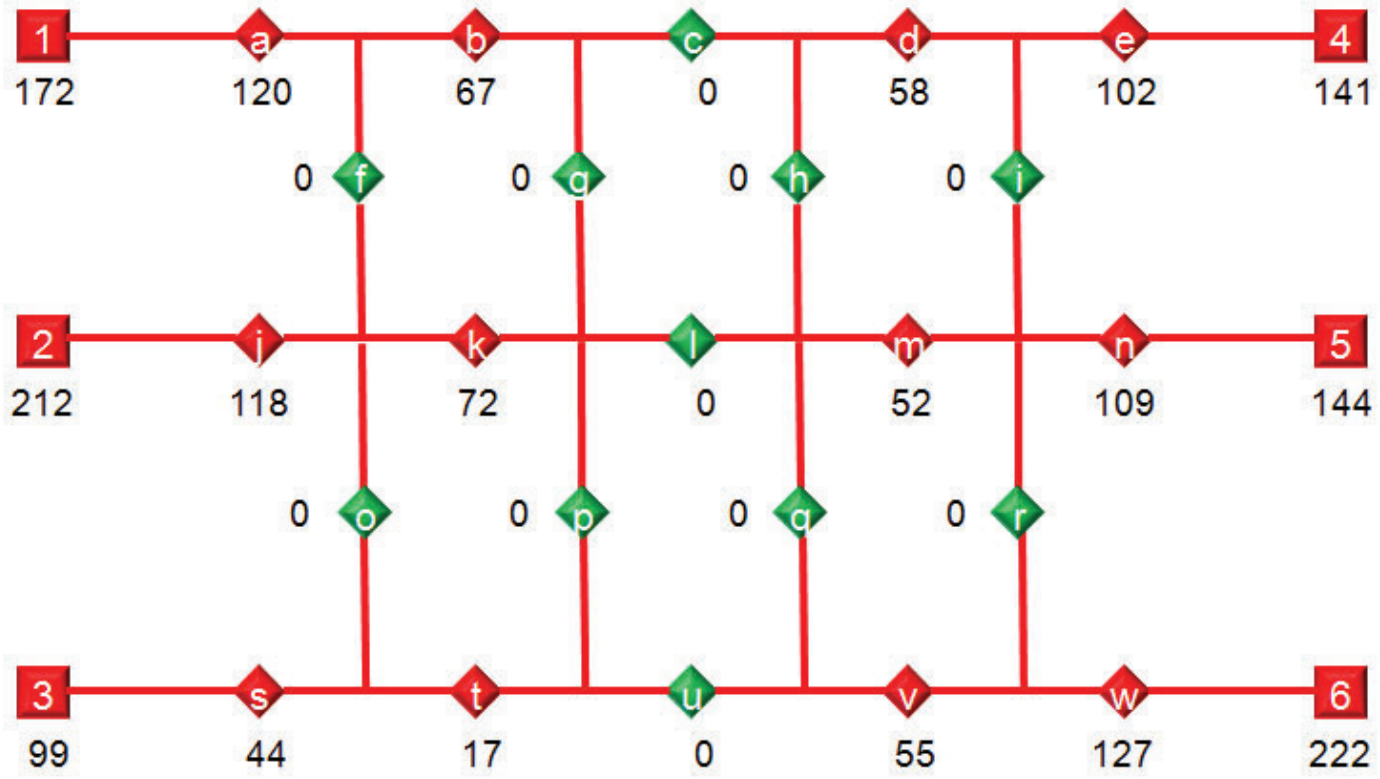
EPRI Subject Matter Experts will consider the proposed DA/FLISR design and roadmap that will be developed in Tasks 1-3 and document a detailed DA/FLISR test plan the evaluate the system along the various stages of Initial Implementation and Production implementation. This test plan will detail specific test cases to be considered to ensure proper operation of the DA/FLISR system, which will be very useful in designing the FLISR logic.

Deliverables

Task 1: Assessment report of the current distribution system
Task 2: DA/FLISR High Level Design Document
Task 3: Program Planning / Roadmap Document
Task 4: DA/FLISR Test Plan

2 FLISR DESIGN & CONTROL LOGIC – LOOP SCHEME TO THE "OPEN MESH"

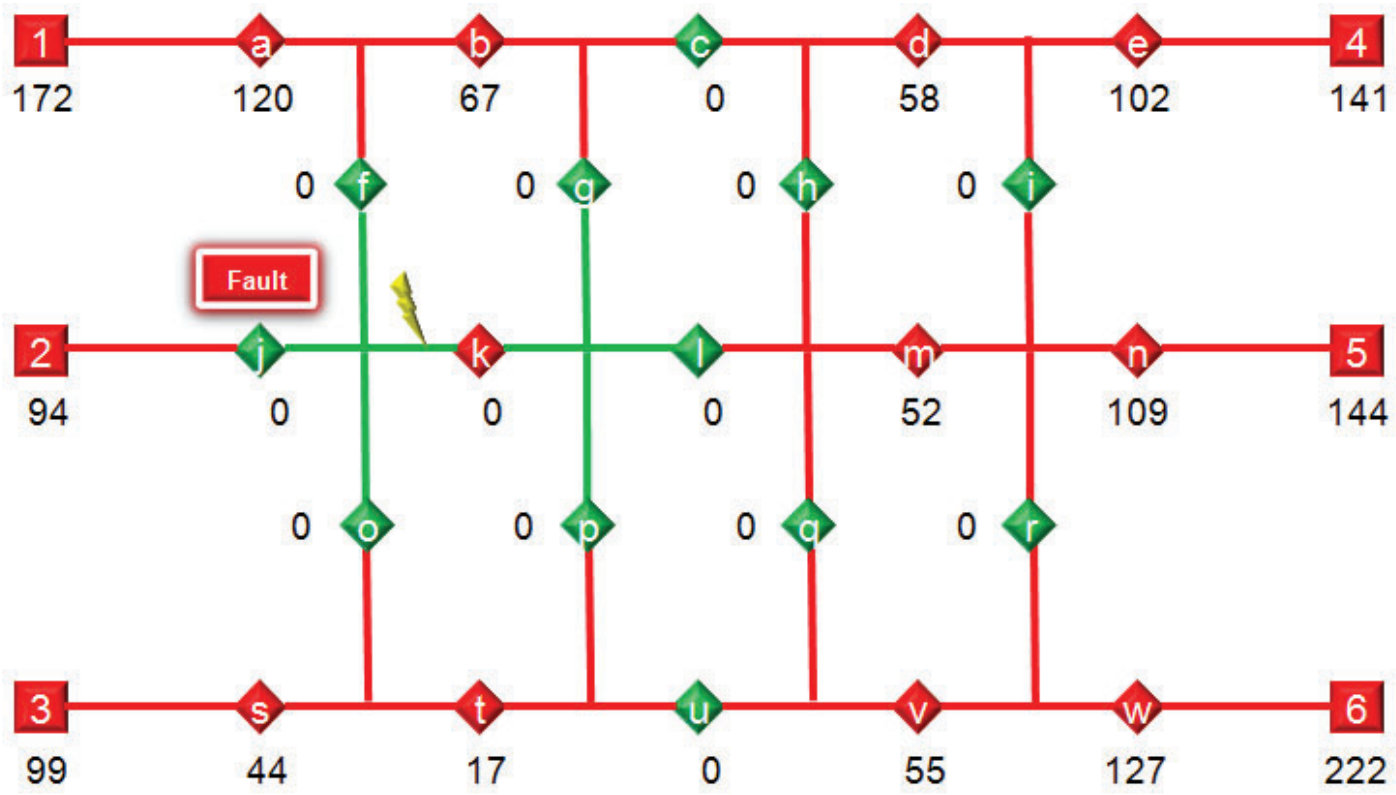
The FLISR application function automatically detects that a fault has occurred, locates the fault (between two medium voltage switches), issues control commands to open the switches that bound the damaged area to isolate the damaged section of the feeder, and then closes other switches (where possible) to restore service to healthy sections of the feeder. The current state-of-the-art allows all of these actions to be completed without manual intervention (fully-automatic). These steps are detailed below in an example showing a set of interconnected overhead feeders (AKA the ***Open Mesh***):



Feeder Automation Scheme – Normal Status

Fault Detection and Location

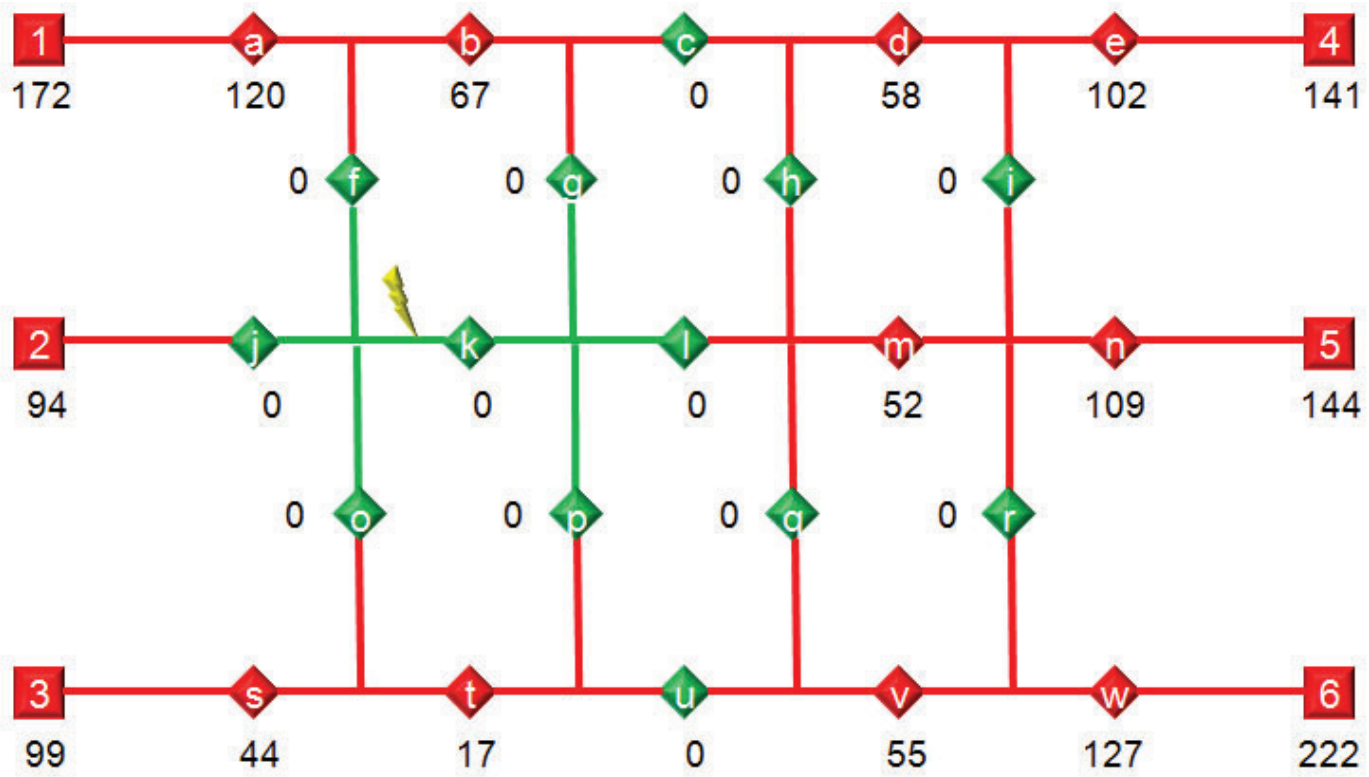
FLISR should only operate following a short circuit (fault) on the feeder itself or in the facilities that normally supply the feeder. FLISR should not operate when a feeder becomes de-energized due to manual switching activities or due to a system wide emergency that triggers under frequency or under voltage load shedding. To meet this requirement, one or more fault detectors are needed to trigger FLISR operation when fault-level currents are detected. Common practice are to either use a protective relay intelligent electronic device (IED) in the substation or a line recloser with self contained protection facilities to determine that a fault occurred. In this example ***recloser j*** locks out in response to the fault.



Fault is Detected and Located

Fault Isolation

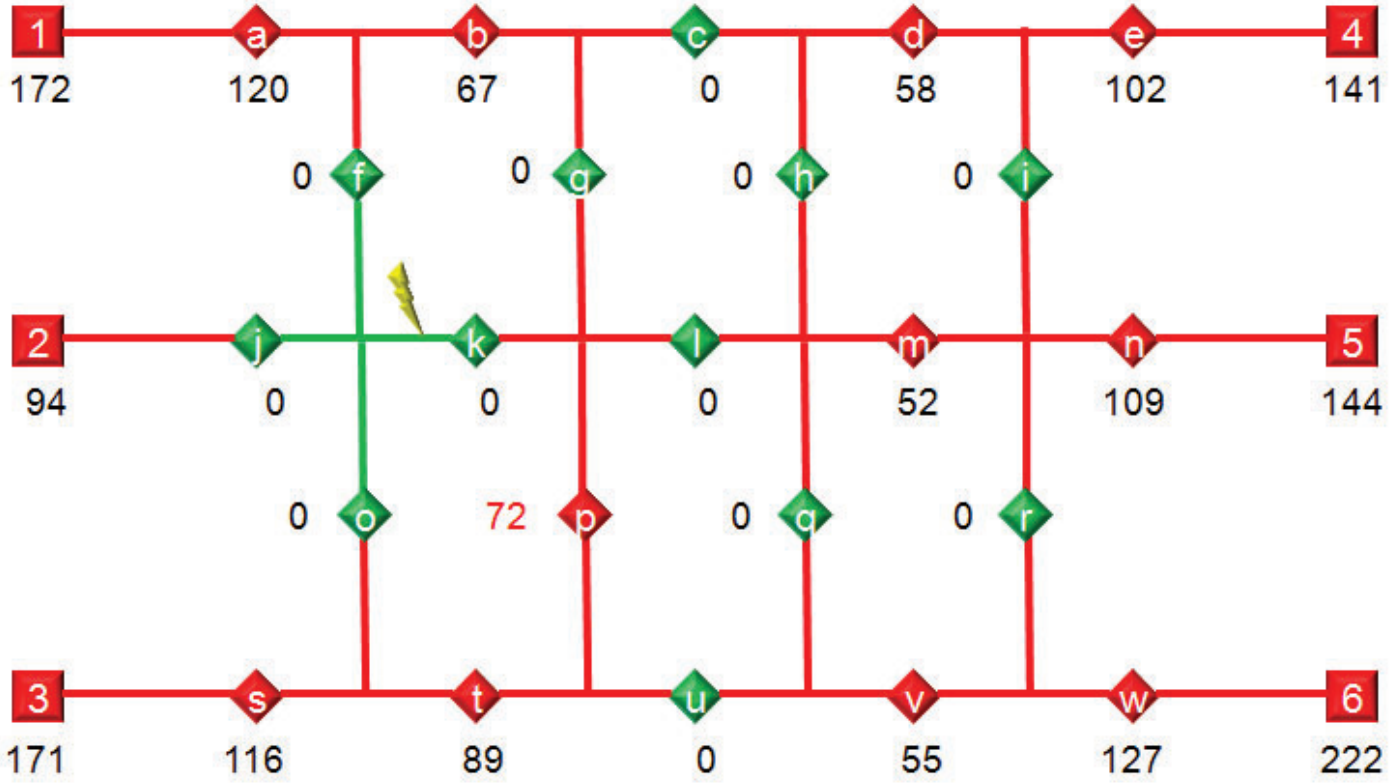
FLISR then issues control commands to open ***recloser k*** to completely isolate the damaged section of the feeder based on the Fault Location analysis described above. It is common practice for FLISR to defer these control actions until the standard automatic reclosing sequence has been completed. This ensures that feeder reconfiguration by FLISR is only performed following a permanent fault (should not reconfigure the feeder if fault is a self-clearing "temporary" fault).



Fault is Isolated

Service Restoration

Once the damaged section of the feeder is isolated, FLISR attempts to restore service to as many "healthy" sections of the feeder as possible via the available sources. Available sources include the normal source of supply to the feeder as well as any available backup sources that are connected to the faulted feeder via normally open, remotely controlled tie switches. Any feeder section that is "upstream" of the faulted feeder section (closer to the substation) can be restored from the original source with no further verification of available capacity. However, to restore feeder sections that are "downstream" of the faulted feeder section, the feeder must have at least one backup source with sufficient capacity to carry the additional load being transferred. Here we see that tie ***recloser p*** is closed to restore the healthy portion of ***feeder 2***.



Service is Restored

Operations Technology Architecture

Operations Technology (OT) is a key enabler of DA/FLISR. Information technology provides the interface with which control center personnel operate the key automation and restoration functions. It provides access to historical data, alarms and logs that engineers, planners and asset managers use to manage the electric system. In centralized deployments it provides the logic which accesses real time status and analog data, driving key restoration decisions and controls. While providing all of these benefits, information technology will also drive many discussions about IT security, server redundancy, integration with other systems, and countless other topics requiring a deep understanding of the strategic and project specific issues.

Options for Deploying DA/FLISR Head End Solution

The head end of a DA/FLISR deployment may be implemented in a number of configurations; decisions which are largely based on where your utility is with their technology life cycle, what the present technology can support, and what vendor relationships are currently in place. Several options with key pros and cons are discussed in the table below.

Option	Description	Pros	Cons
Hosted Solution	Some vendors will provide a hosted (software as a service) solution for DA/FLISR where the communication terminates at their location and the utility interacts via a VPN.	This is the quickest path to getting started. Low cost of entry, suitable for proof of concept or Initial Implementation installations.	Concerns over security and privacy of data. Concerns over scalability and long term support, relying so greatly on a vendor.
Use Substation SCADA without a FLISR module	Simply adding DA devices to the existing substation SCADA is a common approach to getting a DA deployment off the ground.	Another quick path to getting started. Low cost of entry. Can support both Initial Implementation and production deployments.	Lacks FLISR functionality. FERC rules must be followed carefully confidentiality of transmission data. Substation SCADA may lack modern protocols and require a modern front end.
Use Substation SCADA with Home Grown FLISR Module	Add DA devices to the existing substation SCADA and deploy FLISR as a home grown module.	A migration path from reliance on substation SCADA to a fully functional DA/FLISR solution. Allows incremental deployment of FLISR capabilities. Ensures that FLISR code is fully understood and meets utilities unique requirements.	FERC rules must be followed carefully confidentiality of transmission data. Substation SCADA may lack modern protocols and require a modern front end. Requires skilled programmers to design and code FLISR module.

Option	Description	Pros	Cons
DSCADA with Home Grown FLISR Module	Deploy a dedicated Distribution SCADA and integrate a home grown FLISR module.	Eliminates issues related to using Substation SCADA such as FERC concerns and lack of modern protocols. Allows incremental deployment of FLISR capabilities. Ensures that FLISR code is fully understood and meets utilities unique requirements.	Longer path to deployment. Must propose, fund, evaluate options, select a vendor, deploy the system, train operators and test the system. Could take over a year to accomplish this. Requires skilled programmers to design and code FLISR module.
DSCADA with Best in Breed Stand Alone FLISR Module	Deploy a dedicated Distribution SCADA and a best of breed FLISR module.	Eliminates issues related to using Substation SCADA such as FERC concerns and lack of modern protocols. Enables quicker deployment of FLISR functionality with a fully vetted commercially available module.	Longer path to deployment. Must propose, fund, evaluate options, select a vendor, deploy the system, train operators and test the system. Could take over a year to accomplish this. FLISR module will "do what it does" so customization will be limited.
Fully Integrated DMS	Deploy a fully integrated Distribution Management System.	Eliminates need for system integration between DA, FLISR, OMS, etc. Get on the vendor "support train" taking advantage of vendor sponsored and developed new functionality. Necessary to handle the complexity of a distribution system with wide scale deployment of DER and BESS	MUCH longer path to deployment. Must propose, fund, evaluate options, select a vendor, deploy the system, train operators and test the system that doesn't just impact DA/FLISR, but re-engineers the control room. Could take several years to accomplish this.

DA/FLISR Head End OT Solution Options

Given the circumstances that Consumers Energy is presently in, with an ADMS that is deployed and has the necessary FLISR adavanced algorithm nearly ready to deploy, and a future vision of greater levels of DER deployments, the decision to move forward with the ADMS model based FLISR solution is appropriate and well supported.

Device Selection

Each of the typically utilized DA switching devices has pros and cons that cover installation, operation, maintenance, and total cost of ownership. The following table presents these pros and cons.

Feature/Function	Recloser	Pulse Closer	Sectionalizer	Self Contained Switch	Motorized Disconnect
Prevent Momentaries to upstream customers	Yes	Yes	No	No	No
Embedded Sensing	Yes	Yes	Yes	Yes	No
Load Break	Yes	Yes	Yes	Yes	Maybe
Visible Break	Option	Option	Yes	Yes	Yes
Fault Detection	Yes	Yes	Yes	No	No
Coordination Required	Yes	Yes	No	No	No
Automatically Sectionalize	Yes	Yes	Yes	No	No
Minimize voltage sags to upstream customers	No	Yes	No	No	No
Limit fault current duty for upstream devices	No	Yes	No	No	No
Provides protection at Tie during restoration	Yes	Yes	No	No	No
Single Phase Trip/LO Option	Yes	Yes	Yes	No	No

Given the experience with and goals for the DA/FLISR program, the selection of Reclosers for both mainline/backbone and open tie installations is well supported and consistent with many successful DA programs.

3 DA/FLISR PROGRAM PLANNING AND ROADMAP

Recommended Actions	Year 1				Year 2				Year 3				Year 4				Year 5			
1. New engagement with OSI to remediate gaps / issues with FLISR	■	■	■	■	■	■	■	■												
1.a. Conduct FLISR Testing / Validation to support Manual Operations potentially identify new gaps/issues		■	■																	
1.b. Document Requirements of New Gaps / Issues found during testing to OSI				■																
1.c. OSI Resolve FLISR gaps / issues					■	■	■													
1.d. FLISR Algorith Fully Deployed with OSI fixes / patches								■												
2.a. Select FLISR Initial Implementation Area	■	■																		
2.b. Validate FLISR Initial Implementation Area Models			■	■																
2.c. Incorporate necessary aspects of subdstation model into GIS/ADMS to support FLISR					■	■	■	■												
2.c. Validate DFP for Initial Implementation Area							■	■												
3.a. Purchase DA Reclosers for Initial Implementation Area		■	■	■																
3.b. Design DA Reclosers for Initial Implementation Area			■	■																
3.c. Install DA Reclosers for Initial Implementation Area					■	■														
3.d. Commisison DA Reclosers for Initial Implementation Area							■	■												
4. Develop Standards for DA/FLISR Deployment	■	■	■	■	■	■	■	■												
4.a. Develop DA/FLISR HMI Display & Dashboard Standards			■	■																
4.b. Develop DA/FLISR Alarming / Notification Standards					■	■														
5. Develop and Deliver DA/FLISR Training to Operators						■	■	■	■											
6.a. Conduct FLISR Initial Implementation Evaluation									■	■	■	■								
6.b. Conduct FLISR Testing / Validation to support Automatic Operations – Use EPRI OPS Lab									■	■	■	■								
6.b. Conduct FLISR Testing / Validation to support Automatic Operations – Use EPRI OPS Lab									■	■	■	■								
6.c. Implement FLISR Automatic Mode													■	■						
7 Repeat Cycle of Model Validation, Purchase, Install, Commission, Test new FLISR areas														■	■	■	■	■	■	■

ADMS – Roadmap

ADMS Roadmap			
Current State	**Future State – 1 year**	**Future State – 2 years**	**Future State – 5 years**

• ADMS (OSI) Project
  ○ Went Live in 2021
  ○ ADMS Project has concluded
• ADMS Model
  ○ Model is imported from Emap (GIS) every 2 weeks
  ○ Model does not include substation
  ○ Model not validated
• ADMS Core Applications
  ○ Using Distribution Power Flow only, but it is not validated
  ○ Using Switch Order Management
  ○ PI Historan deployed
• ADMS Advanced Applications
  ○ Using Volt Var Optimization with CVR enabled
  ○ Operators are using "Very Little" of the Advanced Applications
  ○ FLISR testing was not adequately completed before ADMS project was concluded
	• ADMS (OSI) Project
	  ○ Initiate new engagement with OSI to remediate gaps / issues with FLISR
	• ADMS Model
	  ○ Select FLISR Initial Implementation area to include 2 Loops Schemes and 2 Open Mesh groups to total ~25 feeders
	  ○ Begin Process to validate models for FLISR Initial Implementation
	• ADMS Core Applications
	  ○ Validate DFP for Initial Implementation – EPRI can support
	• ADMS Advanced Applications
	  ○ Perform FLISR testing necessary to support Manual FLISR
	  ○ Feed detected issues back into new project with OSI to resolve
		• ADMS (OSI) Project
		  ○ OSI Project to remediate gaps/issues with FLISR concluded successfully
		• ADMS Model
		  ○ Begin cycle of validating next set of feeder models to deploy on FLISR
		  ○ GIS (Emap) Model import process perfected
		  ○ Begin to incorporate subsation models
		• ADMS Core Applications
		  ○ Validate DSSE using DA and AMI data
		• ADMS Advanced Applications
		  ○ DA/FLISR Algorithm fully deployed with corrections from OSI
		  ○ FLISR Initial Implementation deployed and commissioned in manual mode
		  ○ Perform FLISR testing to support automatic mode
		• DERMS Roadmap
			• ADMS (OSI) Project
			  ○
			• ADMS Model
			  ○ Substations have been incorporated into model
			  ○ ADMS Model fully validated and available for FLISR
			• ADMS Core Applications
			  ○ Operators fluent with use of DFP and DSSE
			• ADMS Advanced Applications
			  ○ DA/FLISR Algorithm in fully automated mode at system wide scale
			  ○ DA/FLISR Algorithm successfully operates on feeders with full scale deployment of Distributed Energy Resources
			• DERMS
			  ○ DERMS deployed at the appropriate time

• SCADA (OSI)
  ○ Existed before ADMS for 16 years
  ○ Monitors Substation Breakers & Feeders
• OMS (OSI)
  ○ Part of DMS Solution
  ○ Approximately 2 years old
  ○ Moving to V 3.4
  ○ Can validate a SCADA device outage
		○ Evaluate based on framework developed by EPRI CCOTF Project	

Current State to Future State: 1 **year**	Future State: 1 year to Future State: 2 years	**Future State:** 2 **years to Future State:** 5 **years**	
• DA/FLISR Algorithm issues have been identified and corrected, algorithm has been tested for "manual mode" operations •	• ADMS DA/FLISR processes have been documented and put into production covering Display Design, Alarming, Operator Controls, Algorithm Configurations, Troubleshooting, and Benefits Reporting	• DA/FLISR algorithm has successfully scaled from Initial Implementation to production, algorithm has been tested for "automatic mode" operations •	
Uncertainties and Barriers for Achieving the Future States:			

• Barriers:
  • ADMS Project has concluded – need funding for vendor activities
  • Importing the Customer Premise information from Emap model is a struggle
  • Have the DA/FLISR modulewith spectra insight but it is not accurate
  • Substation Models not part of GIS Model – therefore not part of ADMS Model
• Uncertainties:
  • How will Vendor prioritize / schedule required system fixes / modifications
  • OSI Spectra Insight violations are not reliable at this time – may impact selction of feeders for FLISR Initial Implementation
  • Not presently using Distribution System State Estimation			

Current Activities to Achieve Future States:			
• Active Planning for 2025 DA/FLISR project • GIS activities to clean and maintain model	•		

Recommended Actions:	

• Near Term (next 3 months)
  ○ Create a plan to address KNOWN issus with the ADMS (GIS Import, OMS Issues with DA devices, others)
  ○ REPEAT the DA/FLISR Site Acceptance Testing to identify additional ADMS product issues for the Vendor to resolve
	• Mid Term (3-9 months)
	  ○ Initiate a project with the Vendor to resolve all of these issues and establish a clean working version of the DA/FLISR algorithm.

Related EPRI Research:	
See table below.	

Prior Research: DMS Core Capabilities

Year	Project	ID
2012	DMS Planning Guide	1024385
2013	Smart Distribution Applications for DER	3002001295
2016	DMS Planning Guide: Switch Order Management	3002007988
2017	Distribution Management System: Requirements Reference	3002011003
2018	Value of a Distribution Management System: Centralized vs Autonomous Control of Distribution Feeders	3002013386
	Open Architecture for Distribution Management Systems	3002013425
	State Estimation: Application and Algorithms for the Distribution System	3002013421
2019	State Estimation: Test Plan	3002015275
2020	Application of Image Processing Algorithms to Improve Predictive Reliability Assessments: Identifying Physical Threats Using GIS and Satellite Imagery	3002018884
	Distribution Switch Order Management: Survey of Current Distribution Practices	3002021449
2022	Guidance on Operations and Planning Grid Model Requirements	3002024833

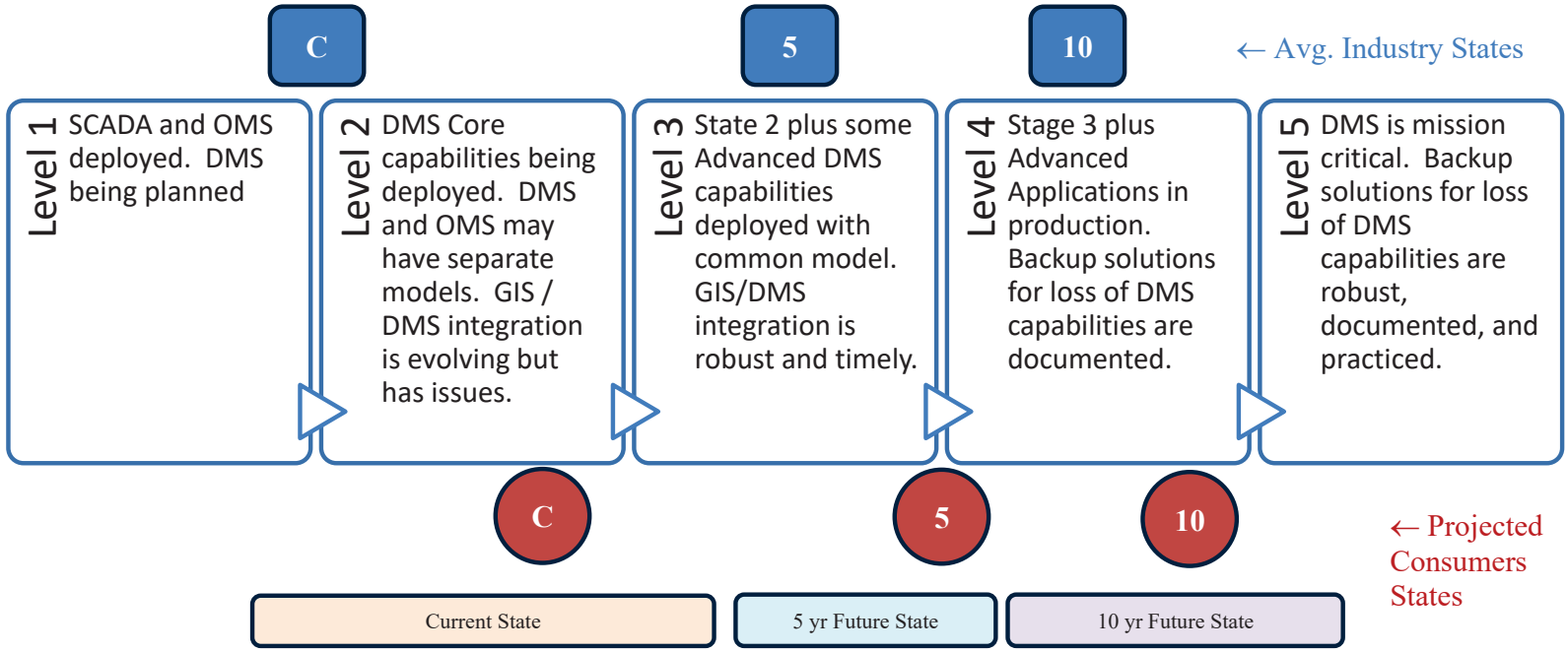
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Prior Research: Advanced DMS Applications

Year	Project	ID
2011	Design and Assessment of Volt -VAR Optimization Systems	1022004
2014	DMS Planning Guide: How to Run a Volt/VAR/CVR Program	3002003244
	Smart Distribution Applications for DER: DMS Use Cases	3002002464
2015	DMS Planning Guide: Load Balancing and Optimal Network Configurations	3002006128
2017	Distribution Management System: Requirements Reference	3002011003
2018	Understanding DERMS	3002013049
2018	A Guidebook to Centralized, Hierarchical, and Local Autonomous Intelligence for Distribution Systems	3002013416
2020	Advanced DMS Algorithms: DA/FLISR, VVO, DSSE with DER – Results of Modelling	3002018868
2021	Advanced DMS Algorithms (DA/FLISR, VVO, DSSE) with DER – Results of Field Demo	3002021448
	Short-Term Forecasting for DER Visibility in Distribution System Operations	3002021931
	Leveraging Short-Term Solar Forecasts for Load Disaggregation and Forecasting to Improve Distribution Operator Visibility	3002022915
2022	Use of AMI and DA for Surgical Load Shedding During Extreme Events	3002024673
2023	Operator Training for DMS Understanding (EPRI U)	

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Comparison of APS to Industry (Based on EPRI RAC Capability Survey)



Distribution Automation – Roadmap

Distribution Automation Roadmap			
Current State	**Future State – 1 years**	**Future State – 2 years**	**Future State – 5 years**

• Existing DA Solution is Traditional Loop Scheme
  ○ 160 Active 2-Feeder Loops
  ○ Exhausted locations appropriate for this solution. Next set of feeders to automate will require complex logic
• DA Reclosers
  ○ NOVA Triple/Single with Form 6
  ○ G&W Viper with SEL 651R2
  ○ Monitored by SCADA
  ○ Device placement manually
  ○ Private Cellular Comm
• Main Driver for DA/FLISR – Reliability
  ○ Presently in 4th Quartile for Reliability
  ○ Goal – Move into 3rd Quartile
  ○ Metric Tracked – SAIDI using 5 minute definition of sustained interruption
	• Deploy ADMS Model Based FLISR
	  ○ Perform testing necessary to ensure Manual FLISR
	  ○ Newly ID'd issues / gaps provided to OSI
	  ○ DA/FLISR Initial Implementation site selected and models validated and corrected
	  ○ Determine aspects of subsation models necessary for FLISR
	• DA Reclosers
	  ○ Reclosers purchased for Initial Implementation installations
	  ○ Initial Implementation implementation of EPRI/Cyme Optimized DA Device Location Algorithm
	  ○ Reclosers designed for Initial Implementation installation
	• Main Driver for DA/FLISR – Reliability
		• Deploy ADMS Model Based FLISR
		  ○ OSI fixes/patches installed and tested
		  ○ Incorporate aspects of substation models necessary for FLISR
		  ○ Standards for HMI, Alarms developed
		  ○ DA Initial Implementation evaluation begins
		  ○ Begin testing of Fully Automated FLISR
		• DA Reclosers
		  ○ Reclosers installed for Initial Implementation
		  ○ Reclosers commissioned for Initial Implementation
		  ○ EPRI/CYME Optimal DA Device Location Algorithm in production
		• Main Driver for DA/FLISR – Reliability
		  ○ Predicted DA benefits are validated
		  ○ Automated process for capturing actual DA
			• Deploy ADMS Model Based FLISR
			  ○ Logic for Complex Feeder Topology tested and in full production
			  ○ 400+ DA Devices deployed on ADMS
			  ○ Substation breaker status, analog monitoring and control integrated into the ADMS model based logic
			  ○ Volt / Var constraints relaxed to account for model and sensor errors to maximize FLISR restoration success
			• DA Recloser Standards
			  ○ Device placement guided by EPRI/Cyme Optimized DA Device Location Algorithm
			• Main Driver for DA/FLISR – Reliability
			  ○ Achieved 3rd Quartile SAIDI
			  ○ New Goal – Move into 2nd Quartile

○ DA/FLISR is a major aspect of the reliability investments to achieve • Pace of Deployments of DA Reclosers ○ 100 New DA Devices per year ○ Robust processes for planning, designing, procuring, commissioning, and installation and in-service • DA Switching / Control ○ Loop switching is "pre-engineered" for peak load conditions ○ 3 Phase Switching, Some 1 Phase Tripping (limited) ○ Fuse Saving disabled on DA/FLISR feeders	○ Process for predicting reliability benefits of DA developed and deployed ○ DA Benefits captured using manual methods • DA Switching / Control ○ DA/FLISR is in Manual Mode for testing	benefits developed and deployed • DA Switching / Control ○ DA/FLISR Initial Implementation is operating in Manual mode ○ Adaptive DMS Model based logic seeks a solution, without need for "pre-engineering" of limits or setpoints	○ DA/FLISR Benefits are tracked and reported automatically • DA Switching / Control ○ DA/FLISR is in Fully Automated Mode ○ Adaptive DMS Model based logic seeks a solution, without need for "pre-engineering" of limits or setpoints ○ Fuse Saving adaptively control to maximize benefits and minimize unnecessary momentaries ○ Existing "Loop Schemes" are integrated into the ADMS Solution (Hybrid or Fully Integrated?)

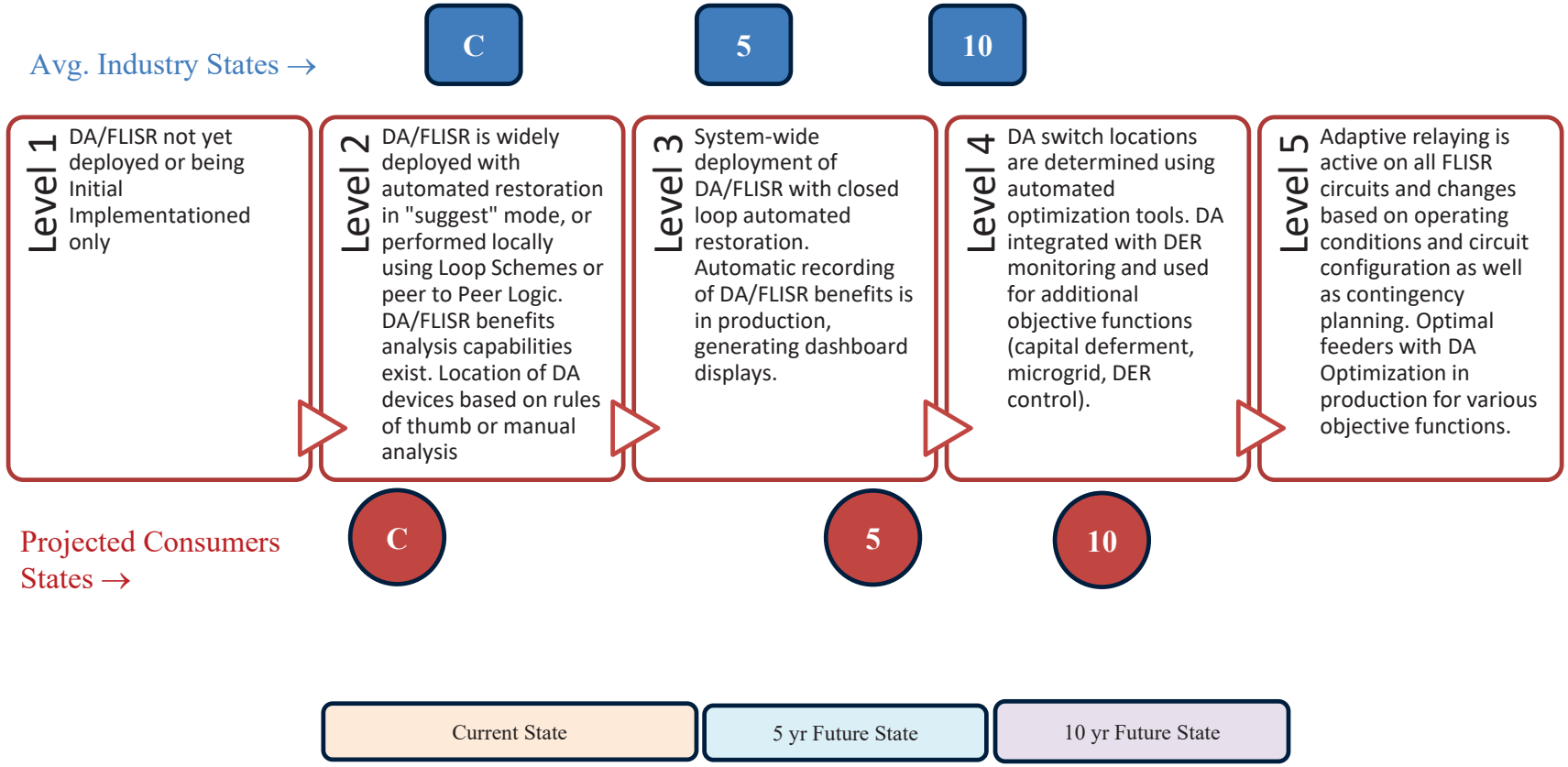
Current State to Future State: 1 year	**Future State: 1 year to Future State: 2 years**	**Future State: 2 years to Future State: 5 years**
• DA/FLISR Testing: Phase 1 Testing – Ensure proper "Manual Mode" Operation, • Integration with EMS necessary to obtain breaker status and control • Change Management: ○ Operator Training and participation in FLISR Testing • Create and implement staffing plan for operations and IT/OT support staff to support planned DA projects. • Fully define IT/OT roles and responsibilities.	• DA/FLISR Testing: Phase 2 Testing – Ensure proper "Automated Mode" Operation • Substations modelled in GIS to provide ADMS with substation models • Determine fate of Loop Schemes – Hybrid Control or Fully Converted • Change Management: ○ Creation of optimized DA/FLISR HMI displays • Deployment of EPRI/CYME Optimal DA Placement Algorithm.	• Integration with EMS necessary to obtain breaker status and control • Substations modelled in GIS to provide ADMS with substation models • Determine fate of Loop Schemes – Hybrid Control or Fully Converted • Change Management: ○ Creation of optimized DA/FLISR Alarms and Dashboards • Training on EPRI/CYME Optimal DA Placement Algorithm. • . •

	Uncertainties and Barriers for Achieving the Future States:
Barriers: • Vendor tools insufficient to achive FLISR testing requirements – Recommend using EPRI Operations Planning Systems Laboratory to perform testing • Alarm Management needs to be implemented – Recommend following EPRI Alarm Management Philosophy • Operator Acceptance of ADMS Model Based FLISR, particularly going from Manual to Automated Mode • No consistency to feeder reliability planning criteria (normal / emergency ratings, number of ties, recloser settings, etc.) Uncertainties: • Timing of Vendor corrections to DA/FLISR algorithm issues • Staffing required (Field, SCADA/DMS Support, IT/OT Support) to achieve objectives • What is proper fate of Loop Schemes	
Current Activities to Achieve Future States:	
• Extensive planning for DA/FLISR deployments.	
Recommended Actions:	
• Immediately begin planning for testing of DA/FLISR Algorithm (in 2 phases) using EPRI OPS Lab • Immediately begin selecting Initial Implementation sites for ADMS DA/FLISR Initial Implementation – Include 2 or 3 Loop Schemes, as well as 2 or 3 groups of interconnected “green field” feeders totalling ~ 25 feeders • Immediately begin implementing the EPRI/CYME DA Optimal Placement Algorithm • Establish an Operator DA/FLISR Change Management Lead (An Experienced/Respected Operator or Operator Trainer). Put them in charge of Operator Training, Developing new DA/FLISR HMI Displays, Developing new DA/FLISR Dashboards, Developing new DA/FLISR Alarming • Consider Establishing a formal DA Technical Role – combining OH PLT, OT Technician, Comm Technician, Protection Technician features	
Related EPRI Research:	
See table below.	

Year	Distribution Automation Research	ID
2013	DMS Planning Guide: How to Run a DA Program	3002001292
	Cost/Benefit Analysis for Smart Distribution Applications v1.1	3002001294
2014	Automated DA Switch Placement	3002003238
	DA/FLISR Automated Measurement and Verification	3002003245
2015	DA with FLISR Automated Measurement and Verification	3002006129
2016	Advanced DMS with DER: DA and FLISR	3002007990
2017	Smart Distribution Applications for DER: Distribution Automation/Fault Location Isolation and Service Restoration	3002011002
	Distribution Automation: Evaluation of Single-Phase Automated Restoration	3002011004
2018	Comparison of Distribution Automation Approaches and Practices	3002013418
	Operational Work Practices for Distribution Automation	3002013426
	Innovative Reliability Statistics for Distribution Automation	3002013422
2019	Innovative Methods to Locate New Feeder Ties for DA	3002015265
2020	Video Training (EPRI U) – Distribution Automation	
2021	Application Guide –Tap Reclosers / Sectionalizers	3002021455
	Optimal DA Switch Placement Tool – SW Deliverable	3002021456
2022	FLISR Performance Testing and User Training Utilizing an Independent System Simulator: Establishing connections to the EPRI OPS Lab	3002024355
	Optimal DA Switch Placement Tool – 2022 Enhancements w/in Drive V4.1	3002024834
2023	Optimal Distribution Automation Switch Placement Tool 2023	3002028454
	Automated Distribution Assessment and Planning Tools (ADAPT) - Recent Advancements and Industry Outreach	3002027033
	FLISR Performance Testing and User Training: Scenarios for Effective System Validation	3002027187
	Short-Term Solar Photovoltaic Forecasting for Distribution Operations: Evaluating the Impact of High PV Penetration on FLISR	3002027190
	Adaptive Protection Schemes for Increasing DER Levels: Identifying Adaptive Protection Solutions That Can Help Increase DER Hosting Capacity	3002027201

Year	Situational Awareness Research	ID
2018	Integrating AMI with Distribution Operations: Use Cases That Benefit Operations	3002013423
	Distribution Control Center Alarm Management: Baseline Reports 2018	3002013424
	HMI/EMS Display Design – Common Design Elements across Generation, Transmission, and Distribution Control Centers	3002013492
2019	Distribution Control Center Alarm Management: Philosophy Guide	3002015266
	Human Machine Interface Designs: For the Distribution Control Centers	3002015270
	Alarm Visualization and Analysis Tool (AVAT)	3002015268
2020	DCC Alarm Management: Guide for Implementing the Research	3002018856
	Operational Benefits of Advanced Metering Infrastructure: Use Cases That Benefit Distribution Operations	3002020147
	Finding Down Conductors With Advanced Metering Infrastructure: Utility Implementation Approaches	3002019883
	Alarm Visualization and Analysis Tool (AVAT)	
2021	HMI Display: Reference Document	3002021448
	Distribution System Dashboards and Displays for Situational Awareness	3002021443
	Distribution Control Center Alarm Management: Alarm Database SW Tool	3002021929
	Distribution System State Estimation: Sensor and Measurement Application Guide	3002023249
	Operational Benefits of Advanced Metering Infrastructure: Use Cases That Benefit Distribution Operations	3002020148

Comparison of Consumers to Industry (Based on EPRI RAC Capability Survey)



4 DEVELOPMENT OF DISTRIBUTION AUTOMATION TECHNICIAN ROLE

A new role has emerge combining some of the skills of a Relay Technnician, a Telecommunications Technician, a Power Line Technician, and a SCADA Technician to support the wide scale delployment of Distribution Automation reclosers. This role has become known in the industry ast the ***DA Technican***. As this role has evolved, the DA technician is typically responsible for a wide variety of activities including, but not limited to:

- Control Programming and Verification of Protection Settings
- In some cases installation of comm equipment and other auxiliary equipment RTACs, clocks, etc. This really depends on the union agreements of the utility.
- ADMS/SCADA Functionality checkout in the field with either access to the necessary back office system or a person they contact to go over a checklist.
- Performing a field installation inspection post construction
- Routine Inspections, Alarm Response, and Maintenance – A mix of visual inspections, responding to alarm that are generated centrally i.e. bad battery/bad control cable (this is the biggest part of the job at this point), and routine maintenance
- Troubleshooting of issues including investigating device failures.

A DA tech would be responsible for recloser/recloser controls, UG switch/switch controls, regulator controls, cap bank controls etc. Some have access to buckets for pole top devices and some do not have that access. It really depends on work rules and training.

An open question, that has not yet been fully determined is how many devices / technician should a utility plan for as full DA deployments mature.

A survey was conducted in 2019 to capture more information about this role. Eight utilities responded to the survey. The results are presented for your consideration:

DA Group Organization Survey

The survey asked utilities were asked how many DA devices (including recloser, automated switches, voltage regulation / capacitor bank controls, etc.) they currently have deployed. The following responses were received:

- 4200
- 548
- 1,000 reclosers, 300 pole top switches, 9,000 line sensors
- 400
- 6000
- 6000+
- ~11,000
- 2500

Does your utility have a separate distribution automation, grid modernization, or smart grid group (from a strategy perspective)? (The group that is responsible for automated restoration, voltage optimization, and system monitoring equipment, and systems like DMS, FLISR and Volt-Var etc.)

The purpose of this survey is to understand how utilities setup their organization related to distribution automation and innovation. The survey shows that 86% of respondents do have designated groups for these specific topics.



Please provide the name and describe the group's objective.

- Grid Modernization: spearheads new technologies to implement upgraded devices and communications to the medium voltage distribution grid.
- Smart Grid Programs include conceptual development of business cases and ongoing performance and event analysis.
- These functions are performed in the Distribution Operations Engineering group and in the Operational Technology group. In the Distribution Operations Engineering group: -There is a cross functional working team on distribution automation strategy. -There is a separate System Automation and Protection group. -Volt var optimization is being addressed by the New Technology group. In Operational Technology: -There is a separate ADMS implementation project team. -There is a separate OT analytics group.
- Grid Modernization Execution - PM Branch to deliver on FLISR/AMDS/VVO Distribution Control and Integrations - Delivers on the capital plan, programs FLISR, VVO and all devices

- Deployment and maintenance of DA equipment by Reliability Support group in each region. SCADA and DMS system by corporate power delivery technology group
- Distribution Automation. Engineering group (14 FTE's) responsible for design specification, programming, program management, and operational analysis of DA devices - primarily focused on sectionalizers and reclosers. DA also has a dedicated group of field engineers (another 14 FTE's) who perform commissioning and troubleshooting of DA devices. Note: The DA Department falls under the same VP as groups dedicated to Voltage Optimization, Reliability Analytics and various other Smart Grid Initiatives. Also, under this VP are Cap Planning, Reliability Projects, Distribution Maintenance Inspections, and Distribution Engineering Standards.
- We do the strategic planning, for the distribution system, to determine the optimum ways to expand and reinforce the distribution system to ensure a reliable long-term supply of power to our customers. This involves defining the Distribution System related: DA Strategy and its implementation plans, Reliability Strategy and its strategic implementation, Planning Guidelines for Voltage & Power Quality Management, Sectionalizing and Circuit Protection Coordination Guidelines, Design Policies for Capacitors, Voltage Regulators, Reclosers/Lateral Reclosers and UG Switchgear, Overall direction for the distribution system and alignment with other corporate strategies, Data Needs, Analytics, and Visualization, EV Strategy for the Distribution system and associated supply/charge equipment, Telecom strategy and implementation.

How many full-time employees does the group have?

- 10
- 6
- 0
- 8-10
- ~30 on reliability support groups around the stare. ~20 in PD tech group
- 14
- 7

At what level is this group managed?

The survey shows that 57% were at the manager level, 14% at the director level, and 29% were others specified below.

The following responses were others obtained in the survey:

- Grid modernization is cross functional work team between the managers for Strategy, Standards, System Automation and Protection and Equipment Engineering.
- Each region reports to a general manager for that area. PDT reports to a differ t general manager

Roughly how many Distribution Automation devices (including recloser, automated switches, voltage regulation / capacitor bank controls) is in their scope? (irrespective of how long for implementation)

- To date: Capacitor control - 4000 Regulator - 100 Automated recloser – 170
- 250
- A dozen or so capacitors and regulators for a CVR Initial Implementation managed by the New Technology group. Long term, plan to install between 4,000 and 9,000 devices
- 400
- Each area has a average of 1000 devices.
- Adding around 4500 devices (sectionalizers and reclosers) next 5 years. Unsure of increase in cap banks as new installations fall under separate Voltage Optimization group.
- 2500

Is the group also responsible for other new technologies such as DER, electric vehicles, data analytics or innovation?

Of the participating utilities 43% reported that their group is also responsible for other new technologies such as DER, electric vehicles, data analytics or innovation and 57% reported that they did not.



The survey also asked utilities that answered yes to provide detail. The following are the responses received for this question:

- DER has recently be brought in with a engineer to head that effort into Grid Modernization. However, other elements such as EV, PV, Wind, Battery storage, energy efficiency, and data analytics are still fragmented among many other organizations across the company.
- DA Engineers are head-up or are included in special projects related to emerging technologies. New DA Engineering subgroup (4 FTE's) dedicated to operational analysis also includes development of data analytics tools into their mission.
- This involves defining the Distribution System related: DA Strategy and its implementation plans, Reliability Strategy and its strategic implementation, Planning Guidelines for Voltage & Power Quality Management, Sectionalizing and Circuit Protection Coordination Guidelines, Design Policies for Capacitors, Voltage Regulators, Reclosers/Lateral Reclosers and UG Switchgear, Overall direction for the distribution system and alignment with other corporate strategies, Data Needs, Analytics, and Visualization, EV Strategy for the Distribution system and associated supply/charge equipment, Telecom strategy and implementation.

DA Deployment Process, Roles and Responsibilities

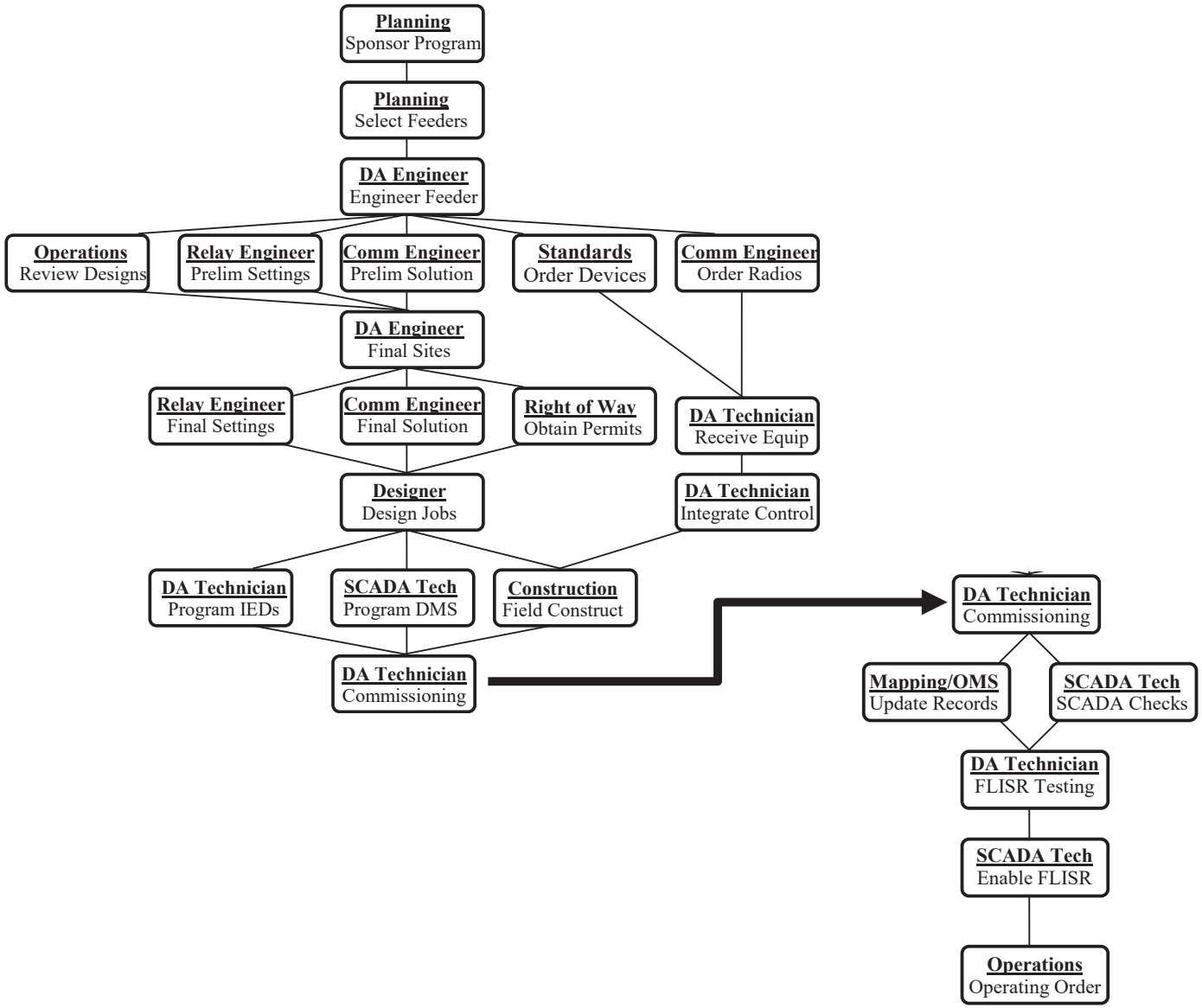
The deployment of Distribution Automation directly involves numerous planning, operating and support groups. In the early phases of a DA deployment, the interactions and hand-offs between these organizations can be managed reasonably well through normal business processes, with informal agreements between organizations keeping the ball rolling. **These informal processes will not scale.** At these higher levels of activity, multiple parallel operations will fail to mesh properly, impeding progress and leading to delays and inefficiencies. Based on the experience of numerous utilities, a detailed process map for DA switch deployment and commissioning should be developed when advancing from proof of concept or Initial Implementation stage to full deployment stage to take advantage of lessons learned, fully engage the organization in a formal way, and ensure that bottlenecks and delays are avoided. This process map should include the following key areas and responsibilities ***(Note: The organization names are as generic as possible, for illustration purposes.).***

Organization	Responsibility	Details
Planning	Sponsor the Program	Typically hold the capital budget
Planning	Identify / Prioritize Feeders to Automate	Using reliability history, identifies the feeders which will provide the greatest benefit per dollar invested
DA or Area Engineering	Preliminary DA designs	Proposes DA switch locations and FLISR schemes and provide this to Operations, Relay and Communications for review.
DA or Area Engineering	Pre-Order Long Lead Time Equipment	Triggers ordering of long lead time or non stock equipment with Standards and Communications.
DA or Area Engineering	Final DA Designs	Incorporates feedback from Operations, Relay and Communications to finalize DA Switch locations and FLISR scheme. Develops control settings to accomplish FLISR goals, based on loads, tie restrictions or other operational restrictions.
Communications	Initial Review	Evaluates communication options to proposed switch locations. May propose repeaters, alternate antennas or alternate locations.
Communications	Final Solution	Engineers final communications solutions for final DA switch location.
Communications	Comm Equipment Order	Orders long lead time communications equipment.
Relay	Initial Review	Develops preliminary protection settings based on locations and DA scheme overview. May propose alternate locations based on loading, fault currents, or coordination restrictions.

Organization	Responsibility	Details
Relay	Final Settings	Engineer's final protection settings for DA switch controller.
Operations	Initial Review	Evaluates DA/FLISR design based on operating restrictions and concerns.
Operations	Operating Order	Following DA switch and FLISR commissioning, issue a formal notice that the scheme is fully in service, along with any specific instructions for that scheme.
Right of Way	Permitting	Obtains necessary permits for DA switch, and communications infrastructure installations.
Designer	Site Specific Design	Using construction standards develops a bill of materials, cost estimate, and design package to enable construction to build the DA switch and required potential transformers. May also be required to obtain specific GPS coordinates.
DA Technician	Receives Equipment	Receives the major equipment (switch, controller, communications module).
DA Technician	Physical Integration	Performs any necessary lab integration of switch, controller and communications modules.
DA Technician	Controller (IED) Settings	Loads and pre-tests protection and control settings in the lab.
DA Technician	Communications Settings	Load and pre-tests communications settings and integration with controller.
DA Technician	Delivers Equipment	After lab integration and testing is performed, delivers switch, controller and communications to Construction for field deployment.
DA Technician	Commissioning Checks	Commissions field installation of DA switch, controller and communications. Performs SCADA checks with SCADA Tech.
DA Technician	FLISR Checks	After the entire automation scheme is commissioned, performs checks of the overall FLISR scheme.
Construction	Order Materials	Orders necessary stock equipment and materials
Construction	Construct	Physically installs the DA switch and control cabinet. Leave the switch in the proper configuration (e.g. open and bypassed) to enable commissioning checks.

Organization	Responsibility	Details
SCADA Tech	Program DMS (DSCADA and FLISR)	Programs the DSCADA database and graphic interface to communicate with the new DA Switch. Once all the DA switches on a Feeder/Scheme are complete, programs or configures the FLISR algorithm. For distributed logic, FLISR programming may be performed by Relay or Area Engineer.
SCADA Tech	SCADA Checks	Performs point to point checks of SCADA mapping to DA switch.
SCADA Tech	FLISR Checks	Tests FLISR programming with DA Technician and enables logic after completion of testing.

DA Process Roles and Responsibilities

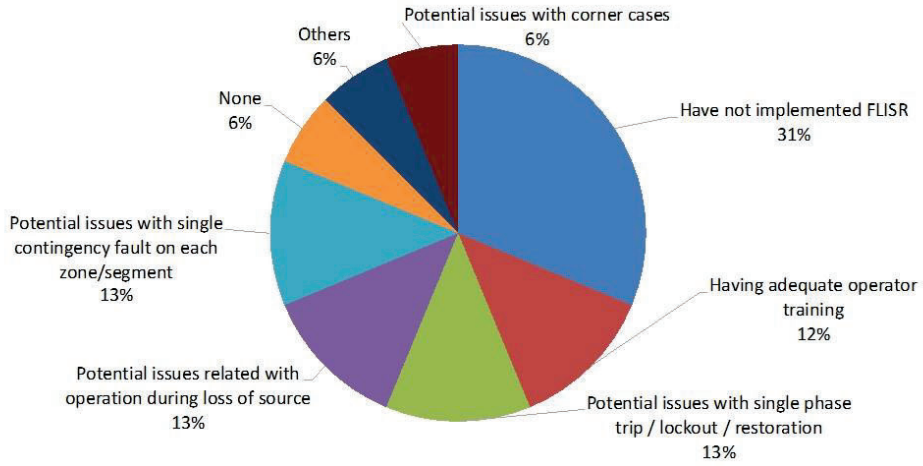

Planning
Sponsor Program
Planning
Select Feeders
DA Engineer
Engineer Feeder
Operations
Review Designs
Relay Engineer
Prelim Settings
Comm Engineer
Prelim Solution
Standards
Order Devices
Comm Engineer
Order Radios
DA Engineer
Final Sites
Relay Engineer
Final Settings
Comm Engineer
Final Solution
Right of Way
Obtain Permits
DA Technician
Receive Equip
Designer
Design Jobs
DA Technician
Integrate Control
DA Technician
Program IEDs
SCADA Tech
Program DMS
Construction
Field Construct
DA Technician
Commissioning
DA Technician
Commissioning
Mapping/OMS
Update Records
SCADA Tech
SCADA Checks
DA Technician
FLISR Testing
SCADA Tech
Enable FLISR
Operations
Operating Order

5 DA/FLISR TESTING

Test Poll Results

Poll on DA/FLISR Testing Concerns

What are your current concerns regarding the performance of the FLISR function in your organization? (16 responses)



- Concerns about FLISR performance are evenly distributed across potential issues with single-phase operation, operation during loss of source, and single contingency operation, as well as having adequate operator training, according to the poll.

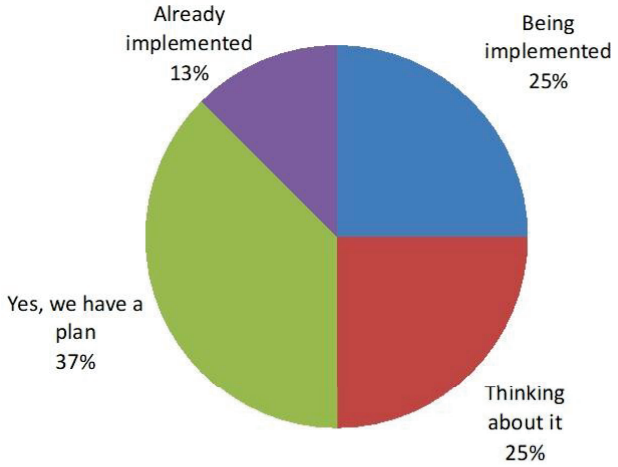
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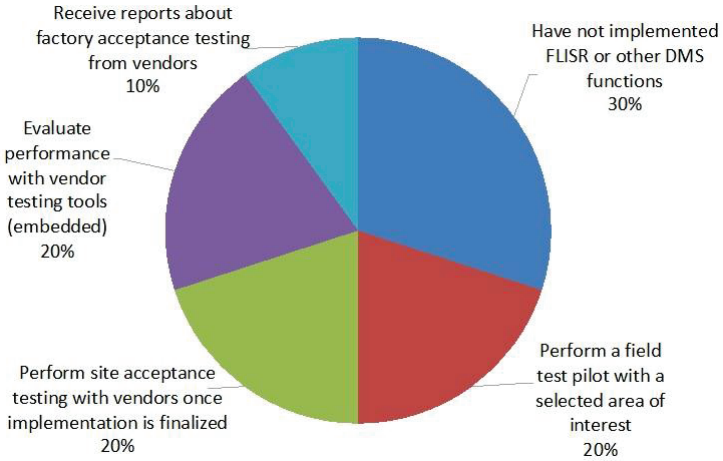
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DA/FLISR Testing Practices Poll Results

Is your company planning to implement a fault location, isolation, and service restoration (FLISR) system to support distribution operations? (8 responses)



Which of the following options are currently being used in your organization to test the implementation of DMS functions such as FLISR? (10 responses)



- 37% of respondents plan to implement FLISR systems, in addition to the 38% who currently have or are in the process of doing so.
- According to the poll, there is a consistent distribution of methods used to test the implementation of FLISR.

19

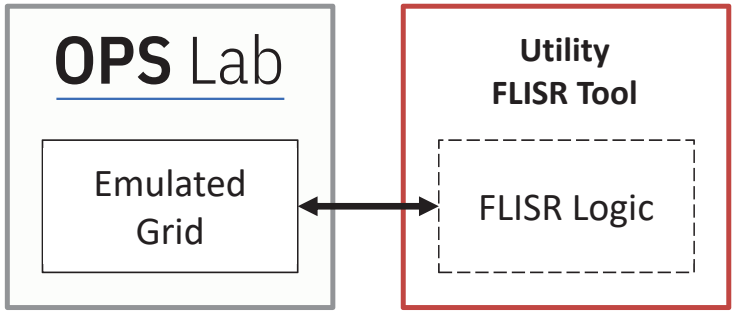
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Test Phases – Manual Mode and Automatic Mode

A well functioning DA/FLISR systems depend on difficult system interactions, operate under abnormal system conditions, and therefore require meticulous testing and validation prior to deployment. Today, testing tools embedded in FLISR systems may have limitations and are not always designed to test complex real-world situations. However, the use of externally emulated grids and detailed test cases has the potential to significantly improve the evaluation capabilities. In doing so, this can enable accelerated deployment of fully automated FLISR functionality, as well as consistent validation of the effectiveness of systems when software or hardware updates are made.

It makes sense to think of DA/FLISR Testing in 2 phases: Testing to satisfy the needs of a Manual Mode operation, and Testing to satisfy the needs of Fully Automatic Mode operation. Many utilities progress from Manual Mode to Fully Automatic Mode, with an extended period of field operation between (perhaps 1 year or more). EPRI has recognized that vendor tools are limited, perhaps idealized, and are not sufficient for enabling utilities to efficienty progress from Manual Mode to Fully Automatic mode. Therefore EPRI has developed capabilities at its Operations, Protection, and Systems Laboratory (OPS Lab) in Knoxville, Tennessee, to simulate complex operating scenarios and provide hands-on experience and insight. Testing FLISR systems with an externally emulated network can increase the realism of FLISR validations by simulating the entire chain of systems involved in reaching field devices and emulating complex IED operations. This has the potential to increase confidence in their use by increasing the realism of test conditions.



Developing test cases for FLISR systems can be challenging because it involves analyzing various scenarios, contingencies, operating modes, and events that can affect system performance. However, creating these test cases is a valuable activity because it builds a knowledge base that can aid in system validation to prevent system malfunction, accelerate system deployment, and provide opportunities for future system enhancements.

Test Cases to Satisfy Manual Mode

These test cases evaluate the FLISR logic's ability to generate a correct fault isolation and restoration switching plan, without regard to the execution and timing of the switch plan, since the execution will be accomplished by an operator via SCADA.

1. Multiple restoration options - Evaluate system response to a single contingency fault in each DA zone with multiple restoration tie options.
2. Restoration with overloaded tie - Evaluate system response to a single contingency fault on each DA zone with an overloaded tie.
3. Restoration with voltage violation - Evaluate system response to a single contingency fault on each DA zone with undervoltage or overvoltage condition after closing tie.
4. Restoration with loss of protection - Evaluate system response to a single contingency fault on each DA zone with low fault current after closing tie (unprotected zones).
5. Restoration with an existing fault on tie feeder - Evaluate system response to a single contingency fault on each DA zone with a second contingency fault affecting a potential tie feeder.
6. Restoration with a subsequent fault - Evaluate system response to a single contingency fault on each DA zone with an additional fault after FLISR has operated.
7. Restoration leading to uncoordinated protection - Evaluate system response to a single contingency fault on each DA zone with a missed coordination event.
8. Restoration with hot line tag in source feeder - Evaluate system response to a single contingency fault on each DA zone with a hot line tag on the feeder that originally supply the faulted zone.
9. Restoration with hot line tag in alternative feeder - Evaluate system response to a single contingency fault on each DA zone with a hot line tag on the alternate feeder that would be used for restoration.
10. Restoration after remote manual operation - Evaluate system response to a single contingency fault on each DA zone with an operator-opened DA device.
11. Restoration after on-site manual operation - Evaluate system response to a single contingency fault on each DA zone with on-site manually opened DA device.
12. Tie trip after restoration - Evaluate system response to a tie switch tripping after implementation of restoration scheme because of an undetermined reason.

13. Loss of voltage sensing at DA switch - Evaluate system response to the loss of voltage measurements associated with the DA switches to be used for isolation or restoration purposes.

Test Cases to Satisfy Automatic Mode

These test cases evaluate the FLISR logic's ability to execute the switch plan, with various issues that may challenge the algorithm to succeed.

1. Communication failure for isolation - Evaluate system response to a single contingency fault on each DA zone with communication failure resulting in failure to operate sectionalizing DA switch.
2. Communication failure for restoration - Evaluate system response to a single contingency fault on each DA zone with communication failure resulting in failure to operate the tie DA switch.
3. Restoration with anticipated voltage violation - Evaluate system response to a single contingency fault on each DA zone and perform limited restoration based on the predicted low voltage from the state estimation prior to the tie closure.
4. Restoration with overloaded tie because of masked load - Evaluate system response to a single contingency fault on each DA zone with DER-masked load issues causing tie or feeder head overloads. (OPTIONAL IF DER IS PRESENT)
5. Restoration with a subsequent high-impedance fault - Evaluate system response to a single contingency fault on each DA zone with a wire slapping event or other high-impedance fault.
6. Restoration leading to new protection coordination - Evaluate system response to a single contingency fault on each DA zone and provide the coordination for stacked protective devices. (OPTIONAL IF DEPLOYED)
7. Transmission system loss event at single substation - Evaluate system response to a transmission or substation fault that affects multiple feeders in a DA scheme.
8. Transmission system loss event at multiple substations - Evaluate system response to a transmission loss affecting multiple substations.
9. Rotating load shedding event - Evaluate system response to a rotating load shedding event.
10. Substation underfrequency trip - Evaluate system response to an underfrequency trip at the substation or DA device.
11. Cascade lockout after restoration - Evaluate system response to a mis-coordination leading to multiple reclosers tripping and reaching lockout after the implementation of the restoration scheme.
12. Delayed SCADA status change after restoration - Evaluate system response to a significant delay of the SCADA in updating the status of switches after restoration scheme has been effectively implemented.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
FLISR Reliability Benefits

Case No.: U-21870
Exhibit No.: A-154 (SAM-13)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Reliability Benefits**	**18,699,168**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

customer population	**1889301**	

Benefits Calculations

SAIDI benefit per regular ATR loop	**0.12**		**assumes 200 CAIDI average duration times average 3217 outages saved per loop per 3 years**	
SAIDI benefit increase from restricted loops	**141%**		**oneway, load limited, and mutually exclusive avoided downtime**	
SAIDI benefit increase from fewer customers affected	**178%**		**sectionalizing benefit factor due to smaller zones affected**	
average incremental SAIDI improvement per loop	**0.1750**	**or CMI:**	**330,628**	
SAIDI benefit per FLISR network	**0.2911**	**or CMI:**	**549,976**	

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
SAIDI	**Sum**		0.58	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Weather Stations Reliability Benefits

Case No.: U-21870
Exhibit No.: A-155 (SAM-14)
Page: 1 of 2
Witness: SAMcPhail
Date: June 2025

Line No.	(a)	(b)	
1	**Total Reliability Benefits**	**$ 12,575,250**	**Avoided CMI**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

14 Hrs	Average restoration time for a typical storm (based on 2024 storms)
82 Hrs	Average restoration time for a catastrophic storm (based on 2024 catastrophic storms)
150	Average # of crews during "Gray Sky" storm
10	Estimate of installation time. (2 hours per weather station, total of 45 weather stations per year)
15	Average # of "Gray Sky" or Larger storms per year
25	Estimate time (hours) for repairs and maintenance
1,889,301	Number of electric customers
18,900	Amount of customers needed to be without power in order for a "Gray Sky" storm to be declared

Benefits Calculations

Reliability SAVINGS CALCULATIONS

18,900	Amount of customers needed to be without powe
60	Number of minutes in the average restoration time saved per storm
15	Average # of "Gray Sky" or Larger storms per year
1,889,301	Number of electric customers
1/14	Fraction of the total restoration time being saved (see A10 for average restoration time for typical storm)
0.64	Total SAIDI Savings per year

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
SAIDI minutes	0.032	0.193	0.643	0.643	0.643	0.643	0.643	0.643	0.643	0.643	0.643	0.643

	Adding 5	Adding 25	Adding 70									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total # of weather stations	5	30	100	100	100	100	100	100	100	100	100	100

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

ASHLEY E. MESCHKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2024 and 2025 EICP Operational Goals

Case No.: U-21870
Exhibit No.: A-156 (AEM-1)
Page: 1 of 1
Witness: AEMeschke
Date: June 2025

Employee Incentive Compensation Plan - Metric Explanation and Measurement or Calculation Method

Line		Metric	Explanation	Measurement or Calculation Method
1	Employee Safety	**Recordable Incident Rate**	Recordable Incident Rate is the number of recordable injuries multiplied by 200,000 (industry standard) divided by the total hours worked	# of recordable injuries * 200,000 / total hours worked
2	Employee Safety	**High Risk Injuries**	Number of injuries (Recordable and Non-Recordable) that are classified against the EEI Safety Classification Learning Model as High Risk which includes: HSIF & PSIF	# of injuries classified as HSIF & PSIF
3	Culture Index	**Employee Engagement Index**	The Employee Engagement index is an average favorability score derived from the taking the total favorable responses received for the 4 questions within the Employee Engagement Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 4 questions: 1. I would recommend my Company as a good place to work. 2. I understand how my job contributes to the Company's strategic priorities and goals. 3. I feel proud to work for the Company. 4. I feel motivated to do more than is required of me.
4	Culture Index	**Employee Empowerment Index**	The Employee Empowerment index is an average favorability score derived from the taking the total favorable responses received for the 4 questions within the Employee Empowerment Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 4 questions: 1. My job makes good use of my skills and abilities. 2. I feel encouraged to come up with new and better ways of doing things. 3. I have enough autonomy to do my job well. 4. There are no significant barriers at work to doing my job well.
5	Culture Index	**Diversity, Equity & Inclusion Index**	The Diversity, Equity and Inclusion index is an average favorability score derived from the taking the total favorable responses received for the 4 questions within the Diversity, Equity and Inclusion Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 4 questions. 1. My Company values and promotes employee diversity. 2. I am treated with respect as an individual. 3. In my work environment, everyone is treated fairly regardless of personal background or characteristics. 4. I feel like I belong at my Company.
6		**Customer Experience Index**	Customer Experience Index is a survey administered by Forrester (https://go.forrester.com/analytics/) and is a measure of customer service based on 3 questions – Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable.	The metric is calculated by asking those 3 questions of customers on a scale of 1 to 5 with 4s and 5s being positive responses, 1s and 2s being negative responses, and 3s being a neutral response. To calculate the score, the number of negative responses is subtracted by the number of positive responses, which is then divided by the total number of customers responding. The results of the three questions are averaged together to calculate the Customer Experience Index score.
7		**Electric Reliability**	Electric Reliability/SAIDI (System Average Interruption Duration Index) is a utility-industry benchmark; SAIDI measures the total time an average customer experiences a non-momentary power interruption in a one-year period.	Use of IEEE (Institute of Electrical and Electronics Engineers) 2.5beta standard to exclude outlier events/MEDs (Major Event Dates); total customer-minutes of interruption divided by total customers served (i.e. customers on the system).
8		**Methane Emmisions Reduction**	Reduce fugitive methane emissions associated with natural gas system. Reductions are obtained as a result of replacing and/or retiring older, aging infrastructure from natural gas distribution.	Summation of reduction in methane emissions associated with Vintage Service Replacements (VSR), Enhanced Infrastructure Replacement Program (EIRP), Other Non-Vintage Replacements (Mains & Services), Well Plug & Abandonment (P&A) and capital replacements from the Leak Backlog. See sub-categories below for more details. Note: Compression Venting was included in previous years; however, is not included in 2025. **Vintage Service Replacements** - The methane emission reductions are calculated using emission factors (EFs) for the type of service replaced (copper and Bare steel). The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **EIRP** - The methane emission reductions are calculated using EFs for the type of main or service replaced. EFs for mains are based on miles replaced while services, as with VSRs above, are based on the number of services. The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **Other Mains & Services** - same calculations as VSR and EIRP. **Well Plug & Abandon** - The methane emission reductions are calculated using emission factors (EFs) for the type of component retired. The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **Gas Leak Backlog** - same calculation as VSR.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Customer Benefits: Employee Safety

Case No.: U-21870
Exhibit No.: A-157 (AEM-2)
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Witness: AEMeschke
Date: June 2025

CE Employee Safety

424.86 Average of daily run rate of Non-Exempt & Union from P&C

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	LOST TIME			**Lost Days**	**Lost Days**	**Lost Days**			
	Year	**# Safety Incidents**	**# Lost Days**	**Per Incident**	**Cost Per Year**	**Per Incident**	**Medical Expense, Workers Comp, Other Exposure (Annual actual paid Workers**	**Per Incident**	
1	2021	135	3207	23.8	$ 1,362,526	$ 10,093	$ 1,306,947	$ 9,681	
2	2022	107	2993	28.0	$ 1,271,606	$ 11,884	$ 2,752,881	$ 25,728	
3	2023	125	2598	20.8	$ 1,103,786	$ 8,830	$ 1,980,835	$ 15,847	
4	2024	139	4062	29.2	$ 1,725,781	$ 12,416	$ 3,369,397	$ 24,240	
5	**Average**	126.5	3215	25.4	$ 1,365,925	$ 10,798	$ 2,352,515	$ 18,597	
6	**2025 Target**	83	2109	23.8	$ 896,219	$ 10,798	$ 1,543,547	$ 17,641	
									Total
7	**Projected Savings**	**11**	**1106**		**$ 469,705**		**$ 808,968**		**$ 1,278,673**
8	**Indirect Cost Savings**	**$889,864**	Notes: 1.1 Multiplier per OSHA Pays Software						
9	**GRAND TOTAL**	**$ 2,168,537**							

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Customer Benefits: Reliability

Case No.: U-21870
Exhibit No.: A-158 (AEM-3)
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Witness: AEMeschke
Date: June 2025

SYSTEM AVERAGE INTERRUPTION DURATION INDEX - SAIDI

Estimated Societal Benefits of Customer Reliability

Line No.	Description [1]	Customers [2] 2024 (000)	Cost of Interruption [3] ($ per min)	COI Std Deviation [3] ($ per min)	SAIDI [4] 2020-2023 (min / cust)	SAIDI [4] 2024 (min / cust)	Cost/(Benefit) to Society [5] Min ($000)	Average ($000)	Max ($000)	Min ($000 per min)	Average ($000 per min)	Max ($000 per min)
1	Residential	1,662.0	$ 0.03	$ 0.04	195	155	$ 216	$ (2,192)	$ (4,601)	$ 5	$ (55)	$ (115)
2	Small C&I	233.0	11.65	7.73	195	155	(36,536)	(108,569)	(180,602)	(913)	(2,714)	(4,515)
3	Medium / Large C&I	2.0	185.19	100.56	195	155	(6,770)	(14,815)	(22,860)	(169)	(370)	(571)
4	Total	1,897.0	----	----	----	----	$ (43,090)	$ (125,576)	$ (208,063)	$ (1,077)	$ (3,139)	$ (5,202)

from OMS as of [3/4/2025]

x 8.0 minute average annual reduction

$ 25,115,262.26

C&I - Commercial and Industrial
COI - Cost of Interruption
SAIDI - System Average Interruption Duration Index
Std Deviation - Standard Deviation

Notes

(1) Consumers Energy commercial class assigned to Small C&I and industrial class assigned to Medium / Large C&I
(2) 2024 customer count data based on premises count from OMS system. The model does not take into consideration any changes to customer counts from 2020 to 2024.
(3) Berkeley National Laboratory "Estimated Value of Service Reliability for Electric Utility Customers in the United States", June 2009
  (a) Estimates based on 2023 mean costs for 4-hour interruption (Tables 3.2, 4.2, and 5.2) adjusted for inflation
  (b) Standard Deviations based on 2021 4-hour interruption (Tables 3.2, 4.2, and 5.2) at 75% confidence level adjusted for inflation
  (c) Inflation based on CPI from Bureau of Labor Statistics
(4) Consumers Energy Company Reliability Reports - excluding Major Event Days

	Actual SAIDI
2020	195
2021	228
2022	182
2023	176
2024	155
CAGR (2024 / 2020)	-5.5%

Average annual SAIDI reduction from 2020 to 2024 = -8.0

(5) Average C/(B) to Society = (COI) x (2024 SAIDI x Customers - 2020 SAIDI x Customers)
  Minimum C/(B) to Society = (COI - Std Dev) x (2024 SAIDI x Customers - 2020 SAIDI x Customers)
  Maximum C/(B) to Society = (COI + Std Dev) x (2024 SAIDI x Customers - 2020 SAIDI x Customers)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Customer Benefits: Culture Index - Reduced Employee Turnover

Case No.: U-21870
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Line No.		(a)	(b)	(c)	(d)	(e)
	Annual Employee Turnover					Average
1	Tenure	2021	2022	2023	2024	
2	<1 - 4 years	4.4%	4.5%	5.5%	5.2%	4.9%
3	5+ years	1.1%	1.6%	1.5%	1.7%	1.5%
4	Total Company	2.0%	2.5%	2.7%	2.6%	2.4%
5	Average Turn Over for peer utilities benchmark					7.3%
6	Average Annual Salary <1-4					$ 99,990
7	Total Employees <1-4					2355
8	2% reduction in turnover for employees with tenure of <1-4 years					47
9	Cost avoidance of 1.5 times average annual salary					$ 7,064,260
10	Cost avoidance of 2.0 times average annual salary					$ 9,419,013

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

MEGAN L. METZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Power Supply Cost Recovery Forecast for May 1, 2026 - April 30, 2027

Case No.: U-21870
Exhibit No.: A-160 (MLM-1)
Page: 1 of 3
Witness: MLMetz
Date: June 2025

SUMMARY BY SOURCE

YEAR		2026 MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2027 JAN	FEB	MAR	APR	Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	0	0	0	0	0	0	0	0	0	0	0	0	0
2	GAS & OIL	1,026,625	1,286,401	1,405,161	1,347,748	1,006,051	700,821	1,215,754	1,216,562	1,312,656	1,213,432	1,230,413	1,050,854	14,012,478
3	NUCLEAR PPA	0	0	0	0	0	0	0	0	0	0	0	0	0
4	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
5	CE OWNED RENEWABLES	224,493	238,895	217,941	205,808	206,868	243,968	279,707	233,385	229,811	333,090	399,178	386,959	3,200,103
6	LCREP RENEWABLES	101,152	103,276	99,009	93,815	80,812	74,519	74,940	45,491	35,164	39,973	38,659	33,052	819,862
7	PEAKERS	0	22,627	59,889	66,375	6,299	0	0	0	6,311	29,512	6,569	7,691	205,273
8	PUMPED STORAGE	4,327	3,597	36,132	65,156	33,707	3,687	24,383	22,860	29,850	40,041	6,868	0	270,607
9	TOTAL GENERATED	1,356,597	1,654,796	1,818,132	1,778,902	1,333,737	1,022,995	1,594,784	1,518,298	1,613,792	1,656,048	1,681,687	1,478,556	18,508,323
10	LESS : PUMPING	-7,544	-5,306	-40,657	-85,138	-44,428	-5,426	-32,016	-33,915	-39,739	-49,104	-9,475	-7,510	-360,257
11	TOTAL GENERATED	1,349,053	1,649,490	1,777,475	1,693,764	1,289,309	1,017,569	1,562,768	1,484,383	1,574,054	1,606,944	1,672,212	1,471,046	18,148,066
12	PURCHASED (NUGs)	566,755	747,778	898,717	844,456	575,004	543,130	407,004	393,995	449,575	636,884	678,687	617,550	7,359,535
13	NET INTERCHANGE	938,248	741,429	739,768	832,393	1,052,038	1,312,545	885,984	1,255,770	1,353,356	756,330	623,482	735,306	11,226,649
14	**TOTAL SYSTEM REQUIREMENTS**	2,854,056	3,138,697	3,415,960	3,370,613	2,916,351	2,873,244	2,855,756	3,134,148	3,376,985	3,000,158	2,974,381	2,823,902	36,734,250
	VARIABLE EXPENSES ($*1000)													
15	COAL STEAM	0	0	0	0	0	0	0	0	0	0	301	0	301
16	GAS & OIL	29,126	36,243	41,839	40,418	29,649	21,803	37,190	40,282	46,324	38,819	34,044	25,039	420,776
17	NUCLEAR PPA VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
18	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
19	CE OWNED RENEWABLES	6,553	5,841	5,852	5,671	5,873	8,307	10,674	8,501	10,766	14,395	15,683	13,634	111,751
20	PEAKERS	402	1,238	2,711	2,987	637	402	392	803	693	1,645	633	622	13,166
21	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
22	TOTAL GENERATED	36,081	43,322	50,403	49,076	36,158	30,512	48,257	49,586	57,783	54,860	50,660	39,296	545,993
23	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
24	TOTAL GENERATED	36,081	43,322	50,403	49,076	36,158	30,512	48,257	49,586	57,783	54,860	50,660	39,296	545,993
25	PURCHASED (NUGs) VARIABLE COST[1]	26,579	33,411	43,023	40,739	26,237	23,383	16,484	16,488	27,099	33,183	33,528	29,969	350,125
26	NET INTERCHANGE, EXCLUDING ZRC	30,583	26,025	25,149	28,050	35,388	45,504	30,965	47,145	52,859	27,554	20,886	22,049	392,157
27	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**93,243**	**102,758**	**118,575**	**117,865**	**97,784**	**99,399**	**95,706**	**113,219**	**137,741**	**115,597**	**105,074**	**91,314**	**1,288,275**
28	ZONAL RESOURCE CREDIT PURCHASE	2,853	1,150	1,188	1,188	1,150	1,188	1,150	1,188	1,188	1,073	1,188	1,150	15,657
29	OWNED RENEWABLE CAPACITY	3,817	3,402	3,409	3,303	3,421	4,839	6,218	4,952	6,271	8,386	9,136	7,942	65,098
30	NUCLEAR PPA CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
31	PURCHASED (NUG) CAPACITY	17,624	18,722	19,430	19,359	17,782	17,415	16,812	14,670	15,722	15,893	17,290	17,116	207,835
32	PURCHASED (NUG) FIXED ENERGY	6,879	6,820	6,943	6,883	6,548	6,464	6,160	5,972	5,998	5,828	6,416	6,388	77,300
33	INDEPENDENT ADMINISTRATOR EXPENSE	0	0	0	0	0	50	50	50	50	50	0	0	250
34	**TOTAL CAPACITY AND NUG FIXED COSTS**	**31,173**	**30,094**	**30,971**	**30,734**	**28,902**	**29,957**	**30,391**	**26,832**	**29,231**	**31,230**	**34,029**	**32,596**	**366,140**
														0
35	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	50,072	60,537	64,605	63,938	55,768	45,655	46,198	50,311	51,641	49,172	48,198	45,768	631,863
36	ACTIVATED CARBON	0	0	0	0	0	0	0	0	0	0	0	0	0
37	MISO - SCHEDULE 2 (REACTIVE)	0	0	0	0	0	0	0	0	0	0	0	0	0
38	AQUEOUS AMMONIA EXPENSE	192	192	192	192	192	192	192	192	205	205	205	205	2,355
39	UREA EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0
40	LIME EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0
41	NOX ALLOWANCE	0	0	0	0	0	0	0	0	0	0	0	0	0
42	**TOTAL POWER SUPPLY COSTS**	**174,681**	**193,581**	**214,343**	**212,728**	**182,645**	**175,203**	**172,487**	**190,554**	**218,817**	**196,205**	**187,507**	**169,883**	**2,288,633**
43	LONG-TERM INDUSTRIAL LOAD RETENTION RATE (LTILRR)	10,040	9,579	9,141	9,720	9,975	10,159	10,384	11,017	11,743	11,813	8,909	9,108	121,588
44	LARGE ECONOMIC DELVEOPMENT RATE	3,785	4,265	5,348	5,468	4,991	4,740	5,251	5,778	6,567	6,541	5,231	5,127	63,092
45	**TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS**	**160,855**	**179,736**	**199,853**	**197,541**	**167,680**	**160,304**	**156,851**	**173,759**	**200,508**	**177,850**	**173,367**	**155,648**	**2,103,953**

[1]Purchased (NUG) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energy plan transfer costs, the green generation program, energy only NUGs and certain hydro plant contract costs

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Power Supply Cost Recovery Forecast for May 1, 2026 - April 30, 2027

Case No.: U-21870
Exhibit No.: A-160 (MLM-1)
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PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2026 MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2027 JAN	FEB	MAR	APR	Total
(a)	(b)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(c)	(d)	(e)	(f)	(o)
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)													
47	MARKET ON PEAK	419,261	343,043	325,948	278,477	438,219	663,345	445,028	723,455	538,089	314,156	284,590	339,009	5,112,621
48	MARKET OFF PEAK	525,117	432,766	514,267	671,007	662,799	649,621	454,639	543,325	846,571	505,041	394,216	411,960	6,611,329
49	PURCHASED (NUGs)	445,490	617,539	769,682	722,663	477,497	473,542	355,559	384,120	433,984	581,406	603,600	526,442	6,391,524
50	TOTAL RECEIVED	1,389,868	1,393,348	1,609,898	1,672,148	1,578,514	1,786,508	1,255,226	1,650,900	1,818,644	1,400,604	1,282,406	1,277,410	18,115,475
	NET INTERCHANGE DELIVERED (MWH)													
51	EXTERNAL SALES	6,130	34,381	100,448	117,092	48,978	421	13,684	11,010	31,306	62,868	55,324	15,663	497,305
52	MISO RAC	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TOTAL DELIVERED	6,130	34,381	100,448	117,092	48,978	421	13,684	11,010	31,306	62,868	55,324	15,663	497,305
54	NET (MWH)	1,383,738	1,358,968	1,509,450	1,555,056	1,529,537	1,786,087	1,241,542	1,639,890	1,787,338	1,337,736	1,227,081	1,261,747	17,618,170

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Power Supply Cost Recovery Forecast for May 1, 2026 - April 30, 2027

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PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2026 MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2027 JAN	FEB	MAR	APR	Total
(a)	(b)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(c)	(d)	(e)	(f)	(o)
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)													
56	MARKET ON PEAK ENERGY	14,301	13,229	13,068	11,150	15,977	24,115	16,316	28,322	22,916	12,342	9,799	10,442	191,976
57	MARKET OFF PEAK ENERGY	16,507	14,053	17,424	23,132	21,753	21,407	15,207	19,454	31,851	18,747	13,179	12,073	224,787
58	PURCHASED (NUGs) ENERGY	25,548	32,356	41,751	39,483	25,184	22,298	15,466	15,285	26,281	32,475	32,831	29,308	338,267
59	CASE NO. U-16048 COST RECOVERY	1,032	1,055	1,272	1,255	1,053	1,085	1,018	1,204	818	708	697	661	11,857
60	TOTAL EXPENSE	57,388	60,693	73,515	75,021	63,967	68,905	48,006	64,265	81,866	64,272	56,505	52,483	766,888
	NET INTERCHANGE CREDIT ($*1000)													
61	EXTERNAL SALE ENERGY	225	1,256	5,343	6,234	2,343	18	557	631	1,908	3,535	2,092	465	24,609
62	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
63	MISO RAC	0	0	0	0	0	0	0	0	0	0	0	0	0
64	TOTAL CREDIT	225	1,256	5,343	6,234	2,343	18	557	631	1,908	3,535	2,092	465	24,609
65	NET EXPENSE	57,163	59,437	68,172	68,787	61,624	68,887	47,449	63,634	79,958	60,738	54,413	52,018	742,279

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Consumers Energy Forecast - Energy Market Sales Revenue and Total Variable Expense

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Exhibit No.: A-161 (MLM-2)
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Capacity Cost Offsets for State Reliability Mechanism Capacity Charge

Line No.	(a) ENERGY (MWH)	(b) MAY	(c) JUN	(d) JUL	(e) AUG	(f) SEP	(g) OCT	(h) NOV	(i) DEC	(j) JAN	(k) FEB	(l) MAR	(m) APR	(n) Total
1	COAL STEAM	0	0	0	0	0	0	0	0	0	0	0	0	0
2	GAS & OIL	1,026,625	1,286,401	1,405,161	1,347,748	1,006,051	700,821	4	1,216,562	1,312,656	1,213,432	1,230,413	1,050,854	12,796,728
3	NUCLEAR PPA	0	0	0	0	0	0	0	0	0	0	0	0	0
4	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
5	CE OWNED RENEWABLES	224,493	238,895	217,941	205,808	206,868	243,968	279,707	233,385	229,811	333,090	399,178	386,959	3,200,103
6	PEAKERS	0	22,627	59,889	66,375	6,299	0	0	0	6,311	29,512	6,569	7,691	205,273
7	PUMPED STORAGE	4,327	3,597	36,132	65,156	33,707	3,687	24,383	22,860	29,850	40,041	6,868	0	270,607
8	LESS : PUMPING	-7,544	-5,306	-40,657	-85,138	-44,428	-5,426	-32,016	-33,915	-39,739	-49,104	-9,475	-7,510	-360,257
9	PURCHASED (NUGs)	566,755	747,778	898,717	844,456	575,004	543,130	407,004	393,995	449,575	636,884	678,687	617,550	7,359,535
10	**TOTAL GENERATED**	**1,814,656**	**2,293,992**	**2,577,183**	**2,444,405**	**1,783,501**	**1,486,180**	**679,082**	**1,832,887**	**1,988,465**	**2,203,855**	**2,312,240**	**2,055,544**	**23,471,989**

		2026								2027				
		MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	Total
11	**Market Price ($/MWh)**	32.83	35.80	40.50	40.07	35.68	35.02	34.95	38.84	41.78	40.72	35.29	30.60	36.84

		2026								2027				
		MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	Total
12	**Energy Market Sales Revenue ($k)**	59,575	82,125	104,376	97,947	63,635	52,046	23,734	71,189	83,078	89,741	81,599	62,900	**871,945**

		2026								2027				
	CE OWNED FUEL EXPENSE ($k)	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	Total
13	COAL STEAM	0	0	0	0	0	0	0	0	0	0	301	0	301
14	GAS & OIL	29,126	36,243	41,839	40,418	29,649	21,803	37,190	40,282	46,324	38,819	34,044	25,039	420,776
15	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
16	CE OWNED RENEWABLES	6,553	5,841	5,852	5,671	5,873	8,307	10,674	8,501	10,766	14,395	15,683	13,634	111,751
17	PEAKERS	402	1,238	2,711	2,987	637	402	392	803	693	1,645	633	622	13,166
18	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
19	**TOTAL FUEL EXPENSE**	**36,081**	**43,322**	**50,403**	**49,076**	**36,158**	**30,512**	**48,257**	**49,586**	**57,783**	**54,860**	**50,660**	**39,296**	**545,993**

	PPA VARIABLE EXPENSE (K$)	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	Total
20														
21	NUCLEAR PPA VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
22	PURCHASED (NUGs) VARIABLE COST	26,579	33,411	43,023	40,739	26,237	23,383	16,484	16,488	27,099	33,183	33,528	29,969	350,125
23	**TOTAL PPA VARIABLE EXPENSE**	**26,579**	**33,411**	**43,023**	**40,739**	**26,237**	**23,383**	**16,484**	**16,488**	**27,099**	**33,183**	**33,528**	**29,969**	**350,125**

24	**Total Variable Expense ($k)**	**545,993**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-162 (MLM-3)
Page: 1 of 1
Witness: MLMetz
Date: June 2025

Summary of PPA Changes from September 30, 2024 to February 1, 2025

Line	(a) PPA	(b) Change	(c) MPSC Case No. U-21592 2025 PSCR Plan Case Commercial Operation Date Forecast (As of Sept. 30, 2024)	(d) Commercial Operation Date Estimated	(e) Nameplate (MW)	(f) Contract Source
1	Heartwood Solar	COD Change	U-20165	3/31/2026	150	IRP
2	Jackson County	COD Change	U-20165	6/1/2026	125	IRP
3	Olivier Solar	Terminated-12/31/2024	U-20604	4/5/2025	20	PURPA
4	Hogan Dairy Solar	Terminated-2/3/2025	U-20604	11/28/2024	12	PURPA
5	Aluminum Solar	Terminated-3/7/2025	U-20604	11/28/2024	8	PURPA

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBIT

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Distribution Investment Recovery Mechanism

Annual Revenue Requirement

($000)

Case No.: U-21870

Exhibit No.: A-163 (HJM-1)

Page: 1 of 3

Witness: HJMyers

Date: June 2025

Line No.	Description	12 Mos. End 4/30/27	12 Mos. End 4/30/28	Source
	(a)	(b)	(c)	(e)
	Capital Investment[1]			
1	Lines Reliability - LVD	276,191	276,191	
2	Resiliency	11,647	11,647	
3	System Protection	4,098	4,098	
4	Repetitive Outages	30,344	30,344	
5	Vulnerable Communities	30,000	30,000	
6	**Total IRM Capital Investment**	**352,280**	**352,280**	Sum Lines 1-5
	Revenue Requirement Summary			
7	Return on Rate Base	13,651	40,584	Page 2, Line 6
8	Depreciation Expense	4,311	13,705	Page 2, Line 9
9	Property Tax	4,282	8,909	Page 2, Line 12
10	**Total Revenue Requirement**	**22,244**	**63,199**	Sum Lines 7-9

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Distribution Investment Recovery Mechanism

Annual Revenue Requirement

($000)

Case No.: U-21870

Exhibit No.: A-163 (HJM-1)

Page: 2 of 3

Witness: HJMyers

Date: June 2025

Line No.	Description	12 Mos. End 4/30/27	12 Mos. End 4/30/28	Source
	(a)	(b)	(c)	(d)
1	Average Plant in Service	144,611	459,718	Page 3 Line 4
2	Average CWIP	31,529	68,702	Page 3 Line 9
3	Average Depreciation Reserve	(2,156)	(11,164)	Page 3 Line 13
4	Average Rate Base	173,984	517,256	Sum Lines 1-3
5	Times Pretax Rate of Return	7.85%	7.85%	Line 13
6	Return on Average Rate Base	13,651	40,584	Line 4 X Line 5
7	Depreciable Balance	144,611	459,718	Line 1
8	Depreciation Rate	2.98%	2.98%	Line 14
9	Depreciation Expense	4,311	13,705	Line 7 X Line 8
10	Taxable Balance	320,751	667,387	p3 Line 3 + 50% Line 8
11	Property Tax Rate	0.01335	0.01335	Line 15
12	Property Tax Expense	4,282	8,909	Line 10 X Line 11
13	Pretax Rate of Return	7.85%		Exh. A-14 (MRB-1), Sch. D-1
14	Depreciation Rate	2.98%		WP-PDD-24
15	Property Tax Rate	0.01335		Exh. A-180 (BJV-1)

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Distribution Investment Recovery Mechanism

Annual Revenue Requirement

($000)

Case No.: U-21870

Exhibit No.: A-163 (HJM-1)

Page: 3 of 3

Witness: HJMyers

Date: June 2025

Line No.	Description	12 Mos. End 4/30/27	12 Mos. End 4/30/28	Source
	(a)	(b)	(c)	(e)
	Plant in Service			
1	Beginning Plant in Service	-	289,222	Line 3
2	Closings	289,222	340,993	(Line 5 + Line 6) * 82.1%
3	Ending Plant in Service	289,222	630,214	Sum Lines 1-3
4	Average Plant in Service	144,611	459,718	Average Line 1 & 3
	Construction Work in Progress			
5	Beginning CWIP	-	63,058	Line 8
6	Capital Spending	352,280	352,280	p1 Line 6
7	Closings	(289,222)	(340,993)	(Line 2)
8	Ending CWIP	63,058	74,346	Sum Lines 4-6
9	Average CWIP	31,529	68,702	Average Line 5 & 8
	Accumulated Depreciation			
10	Beginning Accumulated Depreciation	-	4,311	Line 13
11	Depreciation	4,311	13,705	Page 2 Line 9
12	Ending Accumulated Depreciation	4,311	18,016	Sum Line 10-11
13	Average Accumulated Depreciation	2,156	11,164	Average Line 10 & 12

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

JEFFREY A. MYROM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Schedule: B-5.8

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

Case No.: U-21870
Exhibit No.: A-12 (JAM-1)
Schedule: B-5.8
Page: 1 of 3
Witness: JAMyrom
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ended 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Customer Billing	1,231	13	0	13	0
2	Analytics & Outreach	14	0	0	0	0
3	Credit & Assistance	0	0	680	680	1,870
4	Demand Response (C&I)	287	1,350	60	1,410	180
5	Demand Response (Res)	4,868	656	208	864	1,375
6	PowerMiDrive	1,162	0	229	229	171
7	PowerMiFleet	269	0	0	0	0
8	Total Capital	7,831	2,019	1,177	3,196	3,596

		Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
9	Customer Billing	13	0	0	13
10	Analytics & Outreach	0	0	0	0
11	Credit & Assistance	0	680	1,870	2,550
12	Demand Response (C&I)	450	960	180	1,590
13	Demand Response (Res)	202	662	1,375	2,239
14	PowerMiDrive	0	229	171	400
15	PowerMiFleet	0	0	0	0
16	Total Capital	665	2,531	3,596	6,792

Schedule: B-5.8

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

Case No.: U-21870
Exhibit No.: A-12 (JAM-1)
Schedule: B-5.8
Page: 2 of 3
Witness: JAMyrom
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)
	Historical Year	Projected Bridge Year			Projected Test Year
Line No / Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1 PowerMiDrive	1,162	0	229	229	171
2 Labor	176	-	35	35	26
3 Capitalized E&S	-	-	-	0	-
4 Materials	139	-	27	27	21
5 Contractor	178	-	35	35	26
6 Non-Labor Overhead	487	-	96	96	72
7 Non-Labor Other	181	-	36	36	27
8 Contingency	-	-	-	0	-
9 PowerMiFleet	269	0	0	0	0
10 Labor	41	-	-	0	-
11 Capitalized E&S	-	-	-	0	-
12 Materials	32	-	-	0	-
13 Contractor	41	-	-	0	-
14 Non-Labor Overhead	113	-	-	0	-
15 Non-Labor Other	42	-	-	0	-
16 Contingency	-	-	-	0	-
17 Total "Electric Transportation" Capital	1,431	0	229	229	171
18 Labor	217	0	35	35	26
19 Capitalized E&S	0	0	0	0	0
20 Materials	172	0	27	27	21
21 Contractor	219	0	35	35	26
22 Non-Labor Overhead	600	0	96	96	72
23 Non-Labor Other	223	0	36	36	27
24 Contingency	0	0	0	0	0

Schedule: B-5.8

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

Case No.: U-21870
Exhibit No.: A-12 (JAM-1)
Schedule: B-5.8
Page: 3 of 3
Witness: JAMyrom
Date: June 2025

(a)		(b)	(c)	(d)	(e)
			Projected		
Line No		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
1	PowerMiDrive	0	229	171	400
2	Labor	-	35	26	61
3	Capitalized E&S	-	-	0	0
4	Materials	-	27	21	48
5	Contractor	-	35	26	61
6	Non-Labor Overhead	-	96	72	168
7	Non-Labor Other	-	36	27	62
8	Contingency	-	-	0	0
9	PowerMiFleet	0	0	0	0
10	Labor	-	-	0	0
11	Capitalized E&S	-	-	0	0
12	Materials	-	-	0	0
13	Contractor	-	-	0	0
14	Non-Labor Overhead	-	-	0	0
15	Non-Labor Other	-	-	0	0
16	Contingency	-	-	0	0
17	Total "Electric Transportation" Capital	0	229	171	400
18	Labor	0	35	26	61
19	Capitalized E&S	0	0	0	0
20	Materials	0	27	21	48
21	Contractor	0	35	26	61
22	Non-Labor Overhead	0	96	72	168
23	Non-Labor Other	0	36	27	62
24	Contingency	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Electric Transportation Deferred Asset Costs
($000)

Case No.: U-21870
Exhibit No.: A-164 (JAM-2)
Page: 1 of 1
Witness: JAMyrom
Date: June 2025

Line No.	(a) Description	(b) 2021 Actual	(c) 2022 Actual	(d) 2023 Actual	(e) 2024 Actual	(f) Projected 12-Mos Ending 4/30/2027
1	**PowerMiDrive**					
2	PMD - Education, Awareness, & Labor	1,173	2,262	2,850	3,151	5,843
3	PMD - IT Development	251	883	838	647	570
4	PMD - Residential L2 Rebates	198	0	498	1,099	3,249
5	PMD - Public/Workplace L2 Rebates	465	342	160	457	1,600
6	PMD - Public DCFC Rebates	1,290	390	770	2,380	467
7	PMD - Make Ready	-430	0	0	0	0
8	**PowerMiDrive Total**	**2,947**	**3,876**	**5,116**	**7,734**	**11,729**
9	**PowerMiFleet**					
10	PMF - Education & Awareness	666	1,225	1,202	1,743	2,493
11	PMF - IT Costs	343	420	285	149	528
12	PMF - L2 Rebates	0	140	266	434	1,780
13	PMF - Income Qualified Incentives	0	0	612	946	0
14	PMF - DCFC Rebates	0	0	165	275	0
15	PMF - Make Ready	0	0	378	0	0
16	**PowerMiFleet Total**	**1,009**	**1,785**	**2,906**	**3,548**	**4,801**
17	**Electric Transportation Total**	**$ 3,956**	**$ 5,661**	**$ 8,022**	**$ 11,282**	**$ 16,530**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
PowerMI Drive & PowerMI Fleet Cost Benefit Analysis

Case No: U-21870
Exhibit: A-165 (JAM-3)
Page: 1 of 1
Witness: JAMyrom
Date: June 2025

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
				2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
	Revenue Requirement													
1	TEPs	Rev. Req. "Summary" Tab		$ 7,734,158	$ 10,695,117	$ 13,380,088	$ 16,049,315	$ 19,119,964	$ 21,899,800	$ 24,332,699	$ 27,113,198	$ 29,967,670	$ 32,417,930	$ 35,210,919
	Energy Costs													
2	On Peak Avg LMP ($/kWh)	"Cost Input" Tab		$ 0.03586	$ 0.03788	$ 0.03808	$ 0.03695	$ 0.03644	$ 0.03717	$ 0.03791	$ 0.03762	$ 0.03773	$ 0.03784	$ 0.03795
3	Off Peak Avg LMP ($/kWh)	"Cost Input" Tab		$ 0.03057	$ 0.03317	$ 0.03334	$ 0.03284	$ 0.03236	$ 0.03300	$ 0.03366	$ 0.03384	$ 0.03413	$ 0.03441	$ 0.03470
			On/Off Peak											
4	On Peak Usage (kWh)	"Forecast Input" Tab	6.8%	13,826,262	19,291,954	32,280,272	53,677,868	82,613,300	117,456,211	158,470,614	205,341,088	255,895,978	305,049,294	353,188,598
5	Off Peak Usage (kWh)	"Forecast Input" Tab	93.2%	189,501,124	264,413,246	442,429,609	735,702,538	1,132,288,174	1,609,841,008	2,171,979,589	2,814,380,793	3,507,280,176	4,180,969,742	4,840,761,373
6	Total Usage			203,327,387	283,705,200	474,709,881	789,380,405	1,214,901,475	1,727,297,219	2,330,450,202	3,019,721,880	3,763,176,154	4,486,019,036	5,193,949,971
7	Total Energy Costs			**$ 6,288,836**	**$ 9,500,233**	**$ 15,978,100**	**$ 26,143,166**	**$ 39,645,406**	**$ 57,493,541**	**$ 79,121,039**	**$ 102,971,640**	**$ 129,349,486**	**$ 155,418,747**	**$ 181,361,573**
	Production Capacity Costs													
8	75% of CONE	"Cost Input" Tab		$ 98.20	$ 99.70	$ 101.23	$ 102.78	$ 104.36	$ 105.96	$ 107.58	$ 109.23	$ 110.90	$ 112.60	$ 114.33
9	Demand during 1CP (KW)	"Load Input" Tab		20,497	28,956	49,217	83,400	130,011	186,380	253,482	329,916	415,658	499,012	581,534
10	Total Production Capacity Costs			**$ 2,012,753**	**$ 2,886,933**	**$ 4,982,238**	**$ 8,571,920**	**$ 13,567,455**	**$ 19,747,954**	**$ 27,269,345**	**$ 36,035,835**	**$ 46,096,925**	**$ 56,188,953**	**$ 66,484,351**
	Transmission Costs		Growth Rate											
11	Embedded Cost	"Cost Input" Tab	5.5%	$ 8.35	$ 8.81	$ 9.29	$ 9.80	$ 10.33	$ 10.90	$ 11.49	$ 12.12	$ 12.79	$ 13.49	$ 14.23
12	Demand during 12CP (KW)	"Load Input" Tab		242,492	342,278	579,350	972,976	1,518,969	2,172,889	2,949,018	3,822,102	4,804,008	5,761,465	6,708,335
13	Total Transmission Costs			**$ 2,024,433**	**$ 3,013,927**	**$ 5,380,736**	**$ 9,531,264**	**$ 15,694,403**	**$ 23,679,952**	**$ 33,897,547**	**$ 46,338,357**	**$ 61,431,286**	**$ 77,708,093**	**$ 95,432,338**
	Distribution Costs		Growth Rate											
14	Embedded Cost	"Cost Input" Tab	6.3%	$ 241.62	$ 256.83	$ 273.00	$ 290.19	$ 308.46	$ 327.88	$ 348.53	$ 370.47	$ 393.79	$ 418.59	$ 444.94
15	Demand during 1CP (KW)	"Load Input" Tab		20,497	28,956	49,217	83,400	130,011	186,380	253,482	329,916	415,658	499,012	581,534
16	Total Distribution Costs			**$ 4,952,466**	**$ 7,436,706**	**$ 13,436,345**	**$ 24,201,797**	**$ 40,103,354**	**$ 61,110,695**	**$ 88,345,133**	**$ 122,223,669**	**$ 163,683,721**	**$ 208,880,201**	**$ 258,748,942**
	Total TEP Costs													
17	Costs (RR and Energy Only)			$ 14,022,994	$ 20,195,350	$ 29,358,188	$ 42,192,481	$ 58,765,370	$ 79,393,341	$ 103,453,738	$ 130,084,838	$ 159,317,155	$ 187,836,677	$ 216,572,492
18	Total Costs			$ 23,012,646	$ 33,532,917	$ 53,157,506	$ 84,497,462	$ 128,130,583	$ 183,931,942	$ 252,965,763	$ 334,682,700	$ 430,529,087	$ 530,613,924	$ 637,238,122
19	**Total Related Revenue**	"Revenue Input" Tab		$ 33,435,561	$ 54,171,368	$ 94,059,820	$ 162,233,640	$ 258,777,792	$ 380,695,672	$ 531,570,237	$ 713,006,228	$ 919,850,830	$ 1,135,550,385	$ 1,362,263,163
			WACC											
20	**Net Costs/Revenues**	NPV	6.0%											
21	Rev/RR Energy Only Costs	$1,212,424,788		$ 19,412,567	$ 33,976,019	$ 64,701,632	$ 120,041,159	$ 200,012,422	$ 301,302,332	$ 428,116,498	$ 582,921,390	$ 760,533,675	$ 947,713,708	$ 1,145,690,671
22	Rev/Total Costs	$784,500,177		$ 10,422,916	$ 20,638,452	$ 40,902,314	$ 77,736,177	$ 130,647,209	$ 196,763,730	$ 278,604,474	$ 378,323,528	$ 489,321,743	$ 604,936,461	$ 725,025,040

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)

Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
		Associated HVD Lines Project:							
1	LVD Asset Relocations	Maple City	670	7.2	Miles	LVD Underbuild	Leelanau	Obligation to serve	98,109
2	LVD Asset Relocations	Sonoma	65	0.7	Miles	LVD Underbuild	Calhoun	Obligation to serve	53
3	LVD Asset Relocations	Plainwell	9	0.1	Miles	LVD Underbuild	Midland	Obligation to serve	435,498
4	LVD Asset Relocations	Hodenpyl	363	3.9	Miles	LVD Underbuild	Manistee	Obligation to serve	99,028
5	LVD Asset Relocations	Greenville Relocate	9	0.1	Miles	LVD Underbuild	Montcalm	Obligation to serve	24,255
6	LVD Asset Relocations	Orleans Relocate	9	0.1	Miles	LVD Underbuild	Ionia	Obligation to serve	3
7	LVD Asset Relocations	York Relocate	9	0.1	Miles	LVD Underbuild	Kalamazoo	Obligation to serve	6,284
8	LVD Asset Relocations	Cannonsburg Relocate	9	0.1	Miles	LVD Underbuild	Kent	Obligation to serve	2,652
9	LVD Asset Relocations	Allendale	14	0.2	Miles	LVD Underbuild	Ottawa	Obligation to serve	***
10	LVD Asset Relocations	Bellevue	14	0.2	Miles	LVD Underbuild	Bellevue	Obligation to serve	***
11	LVD Asset Relocations	Golden	84	0.9	Miles	LVD Underbuild	Midland	Obligation to serve	***
12	LVD Asset Relocations	Greenville	168	1.8	Miles	LVD Underbuild	Montcalm	Obligation to serve	***
13	LVD Asset Relocations	Middleville	31	6.0	Poles	LVD Underbuild	Irving, Middleville & Alto	Obligation to serve	63,532
14	LVD Asset Relocations	Metro	10	2.0	Poles	LVD Underbuild	Byron Center & Cutlerville	Obligation to serve	156,166
15	LVD Asset Relocations	Metro	10	2.0	Poles	LVD Underbuild	Byron Center & Cutlerville	Obligation to serve	156,166
16	LVD Asset Relocations	Metro	15	3.0	Poles	LVD Underbuild	Byron Center & Cutlerville	Obligation to serve	156,166
17	LVD Asset Relocations	Bellevue	31	6.0	Poles	LVD Underbuild	Bellevue & Olivet	Obligation to serve	347,374
18	LVD Asset Relocations	Bellevue	56	11.0	Poles	LVD Underbuild	Bellevue & Olivet	Obligation to serve	347,375
19	LVD Asset Relocations	Westphalia	31	6.0	Poles	LVD Underbuild	Bellevue & Olivet	Obligation to serve	326,061
20	LVD Asset Relocations	Westphalia	25	5.0	Poles	LVD Underbuild	Bellevue & Olivet	Obligation to serve	326,061
21	LVD Asset Relocations	Westphalia	5	1.0	Poles	LVD Underbuild	Bellevue & Olivet	Obligation to serve	326,061
22	LVD Asset Relocations	Athens	31	6.0	Poles	LVD Underbuild	Bellevue & Olivet	Obligation to serve	179,791
23	LVD Asset Relocations	Manchester	5	1.0	Poles	LVD Underbuild	Manchester	Obligation to serve	***
24	LVD Asset Relocations	Oberlin	20	4.0	Poles	LVD Underbuild	Sage Twp	Obligation to serve	***
25	LVD Asset Relocations	Oberlin	36	7.0	Poles	LVD Underbuild	Sage Twp	Obligation to serve	***
26	LVD Asset Relocations	Stadium	15	3.0	Poles	LVD Underbuild	Kalamazoo	Obligation to serve	***
27	LVD Asset Relocations	Pole Replacements	4,111	1700.0	Poles	LVD Underbuild	Various locations statewide	Obligation to serve	1,110,165
28	LVD Asset Relocations	Switch Replacements	1,200	50.0	Switches	LVD Underbuild	Various locations statewide	Obligation to serve	104,750
29		**LVD Lines Relocations Total - LVD Underbuild**	**7,056**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 2 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	Right-of-Way Procurement	**6,188**	n/a	n/a	Right of Way			n/a
2		APPR BKBNP14 GOODALE-ROOSEVELT #2 OHS	1	1	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	21060
3		APPR POLE21 HAMILTON_HAMILTON PART 1	200	20	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	180000
4		APPR POLE21 HAMILTON_HAMILTON PART 2	120	10	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	180000
5		APPR POLE21 NORTHERN FIBRE_FIBRE	70	7	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	126000
6		APPR POLE21 PULLMAN_CHICORA PART 1	1,020	54	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	486000
7		APPR POLE21 SAUGATUCK_SAUGATUCK	50	5	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	90000
8		APPR POLE21 WAYLAND_BRADLEY	40	4	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	47037
9		BKBNP13 Burr Oak/Douglas #3 RDSGN	25	5	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	2006
10		BKBNP13 Watkins/Hamilton #1	181	29	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	101,203
11		BKBNP14 COOLEY_EXCHANGE	136	9	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	1800
12		BKBNP14 COOLEY_WESTNEDGE	81	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	490
13		BKBNP14 GOODALE-ROOSEVELT #4 PART 1	68	5	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	101,520
14		BKBNP14 STADIUM NORMAL 1	937	67	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	1000
15		BKBNP16 BLUEGRASS/BLUEGRASS #2	36	9	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	162000
16		BKBNP16 DAVENPORT/CONGRESS #15	190	11	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	227,640
17		BKBNP16 GOGUAC-LAKEVIEW	19	1	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	6480
18		BKBNP16 LIBERTY-WASHINGTON #1	159	19	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	323,280
19		BKBNP16 LIBERTY-WASHINGTON #2	36	10	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	486,360
20		BKBNP16 WESTERVELT/TITTABAWASSEE #6	36	5	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	14000
21		Groundline Inspection	13,300	1,700	Poles	Pole Replacements	Statewide		
22		POLE12 Englishville/Pine Island	46	7	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	138101
23		POLE14 ALABAMA/KING ROAD #1	309	34	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	1,001
24		POLE14 LAKE ODESSA INDUSTRIAL 1	191	33	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	594000
25		POLE14 Plainfield/Belmont # 1	163	11	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	61920
26		POLE14 Plainfield/Belmont # 2	143	7	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	31320
27		POLE14 Plainfield/Belmont # 3	71	6	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	26100
28		POLE14 Plainfield/Wood #3	150	13	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	134742
29		POLE14 Plainfield/Wood #4	163	15	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	146300
30		POLE14 Plainfield/Wood #5	93	8	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	93534
31		POLE15 BURROWS_BURROWS PART 1	500	45	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	823
32		POLE15 CASCADE/THORNCREST 6	86	8	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	2,074
33		POLE15 KAWKAWLIN_RUSSELL - 1	646	51	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	325000
34		POLE15 MIDDLETON/NEWARK #1	1,666	183	poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	743
35		POLE15 PENNFIELD PENNFIELD PT1	21	2	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	6267
36		POLE15 PENNFIELD PENNFIELD PT2	55	10	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	46780
37		POLE15 PENNFIELD PENNFIELD PT3	59	9	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	13865
38		POLE16 GUN LAKE ENGLAND LCP 344 Pt 1	331	21	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	378000
39		POLE16 Orchard Rd / St Andrews #14 LOC 1	19	2	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	36000
40		POLE16 Orchard Rd / St Andrews #2	1,404	14	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	252,000
41		POLE17 LETTS RD/MONROE RD #1	1,065	122	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	300000
42		POLE17 MIDLAND/NORTHWOOD #1	1,465	161	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	2898000
43		POLE18 AUGUSTA_AUGUSTA NO TREAT POLES	328	28	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	45373
44		POLE21 ALDER CREEK_LEE LAKE PART 1	133	12	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	91812
45		POLE21 AUGUSTA_AUGUSTA PT1	355	35	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	67333
46		POLE21 AUGUSTA_AUGUSTA PT2	75	10	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	67333
47		POLE21 AUGUSTA_AUGUSTA PT3	137	10	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	67333
48		POLE21 COOLEY_NORTH STREET PART 1	470	46	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	60084
49		POLE21 COOLEY_NORTH STREET PART 2	138	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	36480
50		POLE21 COOLEY_NORTH STREET PART 3	137	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	20040
51		POLE21 COOLEY_NORTH STREET PART 4	137	10	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	37080
52		POLE21 DELTON_DELTON PART 1	390	39	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	234000
53		POLE21 DELTON_DELTON PART 2	152	13	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	234000
54		POLE21 DELTON_DELTON PART 3	152	13	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	234000
55		POLE21 FINE LAKE_BRISTOL	20	2	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	1132
56		POLE21 GOGUAC_GOGUAC	33	3	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	22953
57		POLE21 JOPPA_JOPPA	130	13	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	62388
58		POLE21 KENDALL_SAGE PART 1	394	18	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	88488
59		POLE21 KINDERHOOK_GILEAD PART 1	333	6	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	31918
60		POLE21 MOSEL_PITCHER	12	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	608
61		POLE21 OAKWOOD_HILLCREST	10	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	37764
62		POLE21 PALMER_WATER LIFT PART 1	772	45	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	771
63		POLE21 PHILLIPS_FACTORY	12	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	1581
64		POLE21 RIX ROAD_UNDERPASS	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	82166
65		**LVD Lines Reliability Subtotal (Pole Replacements)**	**29,711**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 3 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	APPR APPR RLBY BREEDSVILLE LCP 348 - 465	161	0.44	Miles	Zonal Health Improvement	VAN BUREN	Customer-outage-minutes avoided	5100
2		APPR RLBY ALGER_SKIDWAY FIRST ZONE PART	350	2.8	Miles	Zonal Health Improvement	OGEMAW	Customer-outage-minutes avoided	2744457
3		APPR RLBY ALGER_SKIDWAY LCP 661 PART 1	3,622	0.8	Miles	Zonal Health Improvement	OGEMAW	Customer-outage-minutes avoided	263140
4		APPR RLBY TRSF ALGER_SKIDWAY TO GRNWD_RA	507	1.41	Miles	Zonal Health Improvement	OGEMAW	Customer-outage-minutes avoided	1114516
5		APPR RLBY22 NORTH ADAMS_JEROME LCP 832	280	1.05	Miles	Zonal Health Improvement	HILLSDALE	Customer-outage-minutes avoided	243284
6		FAIL CHESANING/CHESANING LCP 365	14	1	project	Zonal Health Improvement	SAGINAW	Customer-outage-minutes avoided	3,553
7		FUSE MILBOURNE_PASADENA LCP SUB	80	0.87	miles	Zonal Health Improvement	GENESEE	Customer-outage-minutes avoided	9,975
8		FUSE23 - HOWARD CITY / CORAL - notif 2	40	18	Fuses	Zonal Health Improvement	MONTCALM	Customer-outage-minutes avoided	9450
9		FUSE23 ALABAMA_YANKEE LCP 931 10	2	1	Fuses	Zonal Health Improvement	SAGINAW	Customer-outage-minutes avoided	525
10		FUSE23 ALTO_ALTO	14	28	Fuses	Zonal Health Improvement	KENT	Customer-outage-minutes avoided	14700
11		FUSE23 ARCADIA_PLEASANTON 13 LOCS	5	13	Fuses	Zonal Health Improvement	MANISTEE	Customer-outage-minutes avoided	6825
12		FUSE23 ARCADIA_STARKE 15 LOCS	13	14	Fuses	Zonal Health Improvement	MANISTEE	Customer-outage-minutes avoided	7350
13		FUSE23 ASHLEY_GARFIELD	12	7	Fuses	Zonal Health Improvement	GRATIOT	Customer-outage-minutes avoided	3675
14		FUSE23 ASHLEY_NORTH STAR	12	22	Fuses	Zonal Health Improvement	GRATIOT	Customer-outage-minutes avoided	11550
15		FUSE23 ASHMAN CIRCLE_SUGNET	9	13	Fuses	Zonal Health Improvement	MIDLAND	Customer-outage-minutes avoided	6825
16		FUSE23 ATHENS_SHERWOOD	1	2	Fuses	Zonal Health Improvement	CALHOUN	Customer-outage-minutes avoided	1050
17		FUSE23 AU GRES_POINT LOOK-OUT	4	7	Fuses	Zonal Health Improvement	ARENAC	Customer-outage-minutes avoided	3675
18		FUSE23 AUSTIN_LONG LAKE	22	17	Fuses	Zonal Health Improvement	KALAMAZOO	Customer-outage-minutes avoided	8925
19		FUSE23 BAYBERRY_KOSTER	2	3	Fuses	Zonal Health Improvement	KENT	Customer-outage-minutes avoided	1575
20		FUSE23 BEAVER_CRUMP	29	21	Fuses	Zonal Health Improvement	BAY	Customer-outage-minutes avoided	11025
21		FUSE23 BEERS_BALDWIN ROAD LCP 706 10	2	7	Fuses	Zonal Health Improvement	GENESEE	Customer-outage-minutes avoided	3675
22		FUSE23 BELSAY_BELSAY	17	14	Fuses	Zonal Health Improvement	GENESEE	Customer-outage-minutes avoided	7350
23		FUSE23 BITTERSWEET_RIVER ROAD	43	46	Fuses	Zonal Health Improvement	ALLEGAN	Customer-outage-minutes avoided	24150
24		FUSE23 BRADFORD_DISTRIBUTION LOC 1-17	9	50	Fuses	Zonal Health Improvement	MIDLAND	Customer-outage-minutes avoided	26250
25		FUSE23 BRISTOL_MILLER	3	3	Fuses	Zonal Health Improvement	SAGINAW	Customer-outage-minutes avoided	1575
26		FUSE23 BRONSON_MONROE LAKE	7	6	Fuses	Zonal Health Improvement	BRANCH	Customer-outage-minutes avoided	3150
27		FUSE23 BURROWS_GRATIOT	22	35	Fuses	Zonal Health Improvement	SAGINAW	Customer-outage-minutes avoided	18375
28		FUSE23 BYRON CENTER_CARLISLE LCP 247_31	1	2	Fuses	Zonal Health Improvement	KENT	Customer-outage-minutes avoided	1050
29		FUSE23 CADILLAC_BOND	13	17	Fuses	Zonal Health Improvement	WEXFORD	Customer-outage-minutes avoided	8925
30		FUSE23 CAMELOT LAKE_COLEMAN LOCS 1-14	9	34	Fuses	Zonal Health Improvement	MIDLAND	Customer-outage-minutes avoided	17850
31		FUSE23 CAMELOT LAKE_LOOMIS	15	23	Fuses	Zonal Health Improvement	MIDLAND	Customer-outage-minutes avoided	12075
32		FUSE23 CARSON CITY_HOSPITAL 1-14	32	35	Fuses	Zonal Health Improvement	MONTCALM	Customer-outage-minutes avoided	18375
33		FUSE23 CASINO_LEATON	10	6	Fuses	Zonal Health Improvement	ISABELLA	Customer-outage-minutes avoided	3150
34		FUSE23 CEDAR LAKE_KINGS CORNER	14	24	Fuses	Zonal Health Improvement	IOSCO	Customer-outage-minutes avoided	465743
35		FUSE23 CEDAR SPRINGS_WHITE CREEK	22	5	Fuses	Zonal Health Improvement	KENT	Customer-outage-minutes avoided	2625
36		FUSE23 CERESCO_RURAL	11	7	Fuses	Zonal Health Improvement	CALHOUN	Customer-outage-minutes avoided	3675
37		FUSE23 CHARLOTTE_FOOTE STREET	17	16	Fuses	Zonal Health Improvement	EATON	Customer-outage-minutes avoided	8400
38		FUSE23 CHARLOTTE_SEMINARY STREET	19	20	Fuses	Zonal Health Improvement	EATON	Customer-outage-minutes avoided	10500
39		FUSE23 CHARLOTTE_WATER WORKS	12	10	Fuses	Zonal Health Improvement	EATON	Customer-outage-minutes avoided	5250
40		FUSE23 CHESANING_PEET	50	25	Fuses	Zonal Health Improvement	SAGINAW	Customer-outage-minutes avoided	13125
41		FUSE23 CLARKSVILLE_CLARKSVILLE 1	15	21	Fuses	Zonal Health Improvement	IONIA	Customer-outage-minutes avoided	17850
42		FUSE23 CLARKSVILLE_MORRISON LAKE 1	16	21	Fuses	Zonal Health Improvement	IONIA	Customer-outage-minutes avoided	3000
43		FUSE23 COLLEGE PARK_MADISON	6	9	Fuses	Zonal Health Improvement	LENAWEE	Customer-outage-minutes avoided	4725
44		FUSE23 CONVIS_MAR CREEK	59	12	Fuses	Zonal Health Improvement	CALHOUN	Customer-outage-minutes avoided	6300
45		FUSE23 COOPERSVILLE_CONKLIN	8	9	Fuses	Zonal Health Improvement	OTTAWA	Customer-outage-minutes avoided	4725
46		FUSE23 COWAN LAKE_RAMSDELL	41	24	Fuses	Zonal Health Improvement	KENT	Customer-outage-minutes avoided	12600
47		FUSE23 CTR CAMELOT LAKE_COLEMAN 15-30	33	20	Fuses	Zonal Health Improvement	MIDLAND	Customer-outage-minutes avoided	10500
48		FUSE23 CTR JONESVILLE_MILNES	4	7	Fuses	Zonal Health Improvement	HILLSDALE	Customer-outage-minutes avoided	3675
49		FUSE23 DAVISON_CONTINENTAL	27	25	Fuses	Zonal Health Improvement	GENESEE	Customer-outage-minutes avoided	13125
50		FUSE23 DAVISON_DELVE	5	4	Fuses	Zonal Health Improvement	GENESEE	Customer-outage-minutes avoided	2100
51		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**5,721**						

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Bridge Period LVD Project List

For the Bridge Period 16 Months Ending April 30, 2026

($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	FUSE23 DEAN ROAD_SHANNON LAKE	5	3	Fuses	Zonal Health Improvem	LIVINGSTON	Customer-outage-minutes avoided	1575
2		FUSE23 DEWITT_DEWITT	14	16	Fuses	Zonal Health Improvem	CLINTON	Customer-outage-minutes avoided	8400
3		FUSE23 DEXTER TRAIL_MURRAY	2	8	Fuses	Zonal Health Improvem	INGHAM	Customer-outage-minutes avoided	4200
4		FUSE23 DIXIE_BRANCH ROAD	62	10	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	5250
5		FUSE23 DIXIE_GEORGE STREET	9	6	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	3150
6		FUSE23 DIXIE_HARVARD	4	2	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	1050
7		FUSE23 DUNHAM_FREEMAN LCP 464 2	2	1	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	525
8		FUSE23 EDMORE_SIX LAKES LOC 1-12	154	30	Fuses	Zonal Health Improvem	MONTCALM	Customer-outage-minutes avoided	15750
9		FUSE23 ENGLISHVILLE_ENGLISHVILLE	6	6	Fuses	Zonal Health Improvem	KENT	Customer-outage-minutes avoided	3150
10		FUSE23 FERGUSON_BROWNS LAKE	16	7	Fuses	Zonal Health Improvem	JACKSON	Customer-outage-minutes avoided	3675
11		FUSE23 FILLMORE_64TH STREET LCP 232 4	1	1	Fuses	Zonal Health Improvem	OTTAWA	Customer-outage-minutes avoided	525
12		FUSE23 FILLMORE_64TH STREET LCP 232 5	2	1	Fuses	Zonal Health Improvem	OTTAWA	Customer-outage-minutes avoided	525
13		FUSE23 FILLMORE_NORTH BLENDON 8-16	24	21	fuses	Zonal Health Improvem	OTTAWA	Customer-outage-minutes avoided	4725
14		FUSE23 FISH LAKE_ROSE	159	21	Fuses	Zonal Health Improvem	OAKLAND	Customer-outage-minutes avoided	11025
15		FUSE23 FOUR MILE_CORDES LCP 7646_1	2	9	Fuses	Zonal Health Improvem	KENT	Customer-outage-minutes avoided	4725
16		FUSE23 FRANKENMUTH_INDUSTRIAL LCP 533_11	2	1	Fuses	Zonal Health Improvem	SAGINAW	Customer-outage-minutes avoided	525
17		FUSE23 FREELAND_RURAL LCP 386_18	3	2	Fuses	Zonal Health Improvem	SAGINAW	Customer-outage-minutes avoided	1050
18		FUSE23 GALESBURG_CHARLESTON	5	5	Fuses	Zonal Health Improvem	KALAMAZOO	Customer-outage-minutes avoided	2625
19		FUSE23 GALESBURG_GALESBURG	11	8	Fuses	Zonal Health Improvem	KALAMAZOO	Customer-outage-minutes avoided	4200
20		FUSE23 GENESEEVILLE_GENESEE	24	15	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	7875
21		FUSE23 GENESEEVILLE_PINEWOOD	21	8	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	4200
22		FUSE23 GERRISH_LEGION SECTION 1	223	61	Fuses	Zonal Health Improvem	ROSCOMMON	Customer-outage-minutes avoided	32025
23		FUSE23 GLEN LAKE_ARBOR 28 LOC	25	17	Fuses	Zonal Health Improvem	LEELANAU	Customer-outage-minutes avoided	8925
24		FUSE23 GLEN LAKE_HOMESTEAD LCP SUB 42	4	9	Fuses	Zonal Health Improvem	LEELANAU	Customer-outage-minutes avoided	4725
25		FUSE23 GOGUAC_GOGUAC	3	8	Fuses	Zonal Health Improvem	CALHOUN	Customer-outage-minutes avoided	4200
26		FUSE23 GRANDVILLE_GEORGETOWN	7	11	Fuses	Zonal Health Improvem	KENT	Customer-outage-minutes avoided	5775
27		FUSE23 GRAYLING_HOSPITAL	24	29	Fuses	Zonal Health Improvem	CRAWFORD	Customer-outage-minutes avoided	15225
28		FUSE23 GRAYLING_RIVER	34	19	Fuses	Zonal Health Improvem	CRAWFORD	Customer-outage-minutes avoided	9975
29		FUSE23 GREENBUSH_GREENBUSH LOC 1-2	124	14	Fuses	Zonal Health Improvem	ALCONA	Customer-outage-minutes avoided	7350
30		FUSE23 GREENBUSH_HARRISVILLE	94	18	Fuses	Zonal Health Improvem	ALCONA	Customer-outage-minutes avoided	9450
31		FUSE23 HANOVER_HANOVER	44	37	Fuses	Zonal Health Improvem	JACKSON	Customer-outage-minutes avoided	19425
32		FUSE23 HOGAN ROAD_ROLSTON	7	7	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	3675
33		FUSE23 HOPKINS_HOPKINS	25	37	Fuses	Zonal Health Improvem	ALLEGAN	Customer-outage-minutes avoided	19425
34		FUSE23 HOWARD CITY/CORAL - notif 1	22	54	Fuses	Zonal Health Improvem	MONTCALM	Customer-outage-minutes avoided	35973
35		FUSE23 HUCKLEBERRY_146TH STREET	17	15	Fuses	Zonal Health Improvem	ALLEGAN	Customer-outage-minutes avoided	7875
36		FUSE23 HUDSON_CITY	23	16	Fuses	Zonal Health Improvem	LENAWEE	Customer-outage-minutes avoided	8400
37		FUSE23 INGERSOLL_LAPORTE	4	4	Fuses	Zonal Health Improvem	MIDLAND	Customer-outage-minutes avoided	2100
38		FUSE23 KILGORE_MT EVEREST LCP SUB 3	2	9	Fuses	Zonal Health Improvem	KALAMAZOO	Customer-outage-minutes avoided	4725
39		FUSE23 KINGSLEY_CENTER RD LOC46-64	8	64	Fuses	Zonal Health Improvem	GRAND TRAVERSE	Customer-outage-minutes avoided	190800
40		FUSE23 LAKE LANSING_BURCHAM	8	5	Fuses	Zonal Health Improvem	INGHAM	Customer-outage-minutes avoided	2625
41		FUSE23 LAKE LEANN_BUNDY HILL LOC 1-25	242	79	Fuses	Zonal Health Improvem	HILLSDALE	Customer-outage-minutes avoided	41475
42		FUSE23 LAKE LEANN_LAKE LEANN 1-20	200	54	Fuses	Zonal Health Improvem	HILLSDALE	Customer-outage-minutes avoided	28350
43		FUSE23 LAKE ODESSA_BONANZA	4	5	Fuses	Zonal Health Improvem	IONIA	Customer-outage-minutes avoided	2625
44		FUSE23 LAKE ODESSA_INDUSTRIAL	9	6	Fuses	Zonal Health Improvem	IONIA	Customer-outage-minutes avoided	3150
45		FUSE23 LARKIN_EASTMAN	13	10	Fuses	Zonal Health Improvem	MIDLAND	Customer-outage-minutes avoided	5250
46		FUSE23 LEITH STREET_FRANKLIN	7	5	Fuses	Zonal Health Improvem	GENESEE	Customer-outage-minutes avoided	2625
47		FUSE23 LEONARD_IONIA	4	3	Fuses	Zonal Health Improvem	KENT	Customer-outage-minutes avoided	1575
48		FUSE23 LEONARD_TAYLOR	21	6	Fuses	Zonal Health Improvem	KENT	Customer-outage-minutes avoided	3150
49		FUSE23 LETTS ROAD_WALKER	17	25	Fuses	Zonal Health Improvem	MIDLAND	Customer-outage-minutes avoided	13125
50		FUSE23 LIBERTY_LIBERTY	5	3	Fuses	Zonal Health Improvem	CALHOUN	Customer-outage-minutes avoided	1575
51		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**1,749**						

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Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	FUSE23 LIBERTY_WASHINGTON	15	10	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	5250
2		FUSE23 LITCHFIELD_ADAMS RD	11	9	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	4725
3		FUSE23 MANCHESTER_AUSTIN ROAD	2	5	Fuses	Zonal Health Improvements	WASHTENAW	Customer-outage-minutes avoided	2625
4		FUSE23 MANCHESTER_DUNCAN	7	7	Fuses	Zonal Health Improvements	WASHTENAW	Customer-outage-minutes avoided	3675
5		FUSE23 MANCHESTER_LOGAN ROAD	4	5	Fuses	Zonal Health Improvements	WASHTENAW	Customer-outage-minutes avoided	2625
6		FUSE23 MAPLE CITY_SUGAR LOAF LCP 738 9	3	2	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	1050
7		FUSE23 MARKEY_FOREST ESTATES	7	10	Fuses	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	5250
8		FUSE23 MARNE_MARNE	13	10	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	5250
9		FUSE23 MAYFAIR_CASS	20	17	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	8925
10		FUSE23 MAYFAIR_HOME	5	4	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	2100
11		FUSE23 MAYFAIR_MAYFAIR	5	4	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	2100
12		FUSE23 MAYFAIR_SHERATON	5	4	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	2100
13		FUSE23 MERRILL_MERRILL	11	23	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	12075
14		FUSE23 MESICK_SHERMAN (1/3)	49	79	Fuses	Zonal Health Improvements	WEXFORD	Customer-outage-minutes avoided	41475
15		FUSE23 MIDLAND_NORTHWOOD	142	16	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	8400
16		FUSE23 MONTEREY_30TH STREET PART 2	25	16	fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	142545
17		FUSE23 MORENCI_MOREY	6	16	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	8400
18		FUSE23 MORRICE_M-78	2	8	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	4200
19		FUSE23 NAPOLEON_NORVELL 1-20	53	51	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	26775
20		FUSE23 NAPOLEON_STONEY LAKE	16	25	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	13125
21		FUSE23 NAPOLEON_WOLF LAKE	14	17	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	8925
22		FUSE23 NASHVILLE_NASHVILLE part 1	30	78	Fuses	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	37225
23		FUSE23 NEW LOTHROP_REED ROAD LCP 417_37	3	13	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	6825
24		FUSE23 NEW RICHMOND_NEW RICHMOND	13	18	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	9450
25		FUSE23 NIAGARA_HAMILTON	44	17	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	8925
26		FUSE23 OKEMOS_FERGUSON PARK	6	8	Fuses	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	4200
27		FUSE23 OKEMOS_WKAR	60	9	Fuses	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	4725
28		FUSE23 OLIVER_CHESTNUT	7	14	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	7350
29		FUSE23 OLIVER_KING STREET	3	3	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	1575
30		FUSE23 ORLEANS_ORLEANS - NEW	25	30	Fuses	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	15750
31		FUSE23 OTSEGO_FARMER	60	46	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	24150
32		FUSE23 PARMA_PARMA	2	5	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	2625
33		FUSE23 PENINSULA_MCKINLEY ROAD	6	4	Fuses	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	2100
34		FUSE23 PENNFIELD_PENNFIELD	24	16	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	8400
35		FUSE23 PINE RIVER_GRATIOT	2	3	Fuses	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	1575
36		FUSE23 PITTSFORD_BIRD LAKE LOC 1-14	27	34	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	17850
37		FUSE23 PORTAGE_CARPENTERS CORNERS	3	4	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	2100
38		FUSE23 PORTAGE_LOVERS LANE	7	9	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	4725
39		FUSE23 PORTAGE_MUSTANGS	6	2	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	1050
40		FUSE23 PORTAGE_SHAVER ROAD	1	2	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	1050
41		FUSE23 PORTSMOUTH_INDIANTOWN 1-11, 13-20	28	36	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	18900
42		FUSE23 POTTER_KIRK	13	6	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	3150
43		FUSE23 PULLMAN_CHICORA	29	57	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	29925
44		FUSE23 PULLMAN_CHICORA #3	17	10	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	5250
45		FUSE23 PULLMAN_CHICORA #4	7	4	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	2100
46		FUSE23 PULLMAN_PULLMAN	17	37	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	19425
47		FUSE23 RAMONA_BLODGETT	31	8	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	4200
48		FUSE23 RAMONA_ROBINSON	12	5	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	2625
49		FUSE23 RANKIN_GREEN VLY LCP 475 4	5	3	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	1575
50		FUSE23 READING_CAMBRIA 1-18	167	39	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	20475
51		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**1,067**						

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Bridge Period LVD Project List

For the Bridge Period 16 Months Ending April 30, 2026

($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 6 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	FUSE23 RED ARROW_BRISTOL	14	11	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	5775
2		FUSE23 RED ARROW_OGEMA	11	7	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	3675
3		FUSE23 RIGA_BIERMAN	5	5	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	2625
4		FUSE23 ROCKFORD_WOLVERINE	12	6	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	3150
5		FUSE23 ROEDEL ROAD_JUNCT ROAD LCP 358_80	4	9	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	4725
6		FUSE23 ROSEBUSH_DELWIN LOC 1-20	127	47	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	24675
7		FUSE23 ROSEBUSH_STEVENSON LAKE	18	10	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	5250
8		FUSE23 RUSSELLVILLE_RICHFIELD	100	77	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	40425
9		FUSE23 SALZBURG_SALZBURG - LOC 1-12	50	21	Fuses	Zonal Health Improvements	BAY	Customer-outage-minutes avoided	11025
10		FUSE23 SARANAC_SARANAC	36	33	Fuses	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	17325
11		FUSE23 SCIPIO_MOSHERVILLE	49	24	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	12600
12		FUSE23 SHEPHERD_FOREST HILL	29	22	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	11550
13		FUSE23 SHERIDAN_FENWICK 1-21	164	54	Fuses	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	28350
14		FUSE23 SHERIDAN_SIDNEY 1-14	98	34	Fuses	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	17850
15		FUSE23 SPRING ARBOR_ARBOR HILLS	6	15	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	7875
16		FUSE23 SPRING ARBOR_CHAPEL	2	5	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	2625
17		FUSE23 SPRINGPORT_DEVEREAUX	15	8	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	4200
18		FUSE23 SPRINGPORT_SPRINGPORT	40	11	Poles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	8925
19		FUSE23 STANTON_STANTON - NEW	12	18	Fuses	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	9450
20		FUSE23 STANWOOD_RIVERSWAY (1-21)	44	43	Fuses	Zonal Health Improvements	MECOSTA	Customer-outage-minutes avoided	22575
21		FUSE23 STARKS_LEE 1-20	402	105	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	55125
22		FUSE23 SUNFIELD_MULLIKEN	6	5	Fuses	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	2625
23		FUSE23 SUNFIELD_SUNFIELD	15	13	Fuses	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	6825
24		FUSE23 SWARTZ CREEK_MAPLE ROAD	4	6	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	3150
25		FUSE23 SWARTZ CREEK_WINCHESTER	11	11	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	5775
26		FUSE23 TECUMSEH_EVANS STREET	18	18	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	9450
27		FUSE23 TECUMSEH_PATTERSON	4	7	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	3675
28		FUSE23 THAYER_RIVER	10	9	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	4725
29		FUSE23 THORNAPPLE_BUTTRICK	14	9	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	4725
30		FUSE23 UNIVERSITY_HARRISON	5	5	Fuses	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	2625
31		FUSE23 VANDERCOOK LAKE_HAGUE ROAD	18	9	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	4725
32		FUSE23 VANDERCOOK LK_ACKERSON LK	27	12	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	6300
33		FUSE23 VENICE_LENNON LCP 244_9	1	5	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	2625
34		FUSE23 WAGER_PARKLAND	105	16	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	8400
35		FUSE23 WAKESHMA_FULTON	13	9	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	4725
36		FUSE23 WAKESHMA_LEONIDAS	7	16	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	8400
37		FUSE23 WALNUT_GILKEY LCP 255 10	5	5	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	2625
38		FUSE23 WAMPLERS_FRANKLIN	11	15	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	7875
39		FUSE23 WAMPLERS_WAMPLERS	8	10	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	5250
40		FUSE23 WEALTHY STREET_LOGAN	3	3	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1575
41		FUSE23 WHITTUM_PETRIEVILLE LOC 1-17	25	31	Fuses	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	16275
42		FUSE23 WOOD STREET_AVENUE A	15	7	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	3675
43		FUSE23 WOOD STREET_MASON	14	15	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	7875
44		FUSE23 YORKVILLE_BAYVIEW	6	4	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	2100
45		FUSE23 YORKVILLE_HIGHLAND PARK	3	6	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	3150
46		GRANT B2CMZ157 ZONE22 DAVENPORT_CO LCPS.	1	10	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	5250
47		GRANT B2CMZ157 ZONE22 DAVENPORT_CO LCPS.	1	1	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	525
48		GRANT B2CMZ157 ZONE22 DAVENPORT_CO LCPS.	1	2	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	1050
49		GRANT FUSE23 ALDER CREEK_LEE LAKE	9	21	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	11025
50		GRANT FUSE23 ANTRIM_BASS LK LC LCP 765_8	1	1	Fuses	Zonal Health Improvements	ANTRIM	Customer-outage-minutes avoided	525
51		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**1,600**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	GRANT FUSE23 ASH ROAD_STERLING ROAD	10	10	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	5250
2		GRANT FUSE23 AUGUSTA_AUGUSTA LCP 675_28	5	3	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	1575
3		GRANT FUSE23 BATES_ACME LCP 21 LCP 216 1	3	2	Fuses	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	1050
4		GRANT FUSE23 BATES_ACME LCP 30 LCP 302 2	2	1	Fuses	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	525
5		GRANT FUSE23 BAY ROAD_BAY ROAD	10	1	Fuses	Zonal Health Improvements	BAY	Customer-outage-minutes avoided	525
6		GRANT FUSE23 BEHNKE_ANGOLA RD LCP 423_16	2	1	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	525
7		GRANT FUSE23 BELL RD_ALBEE LC LCP 870 42	1	3	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	1575
8		GRANT FUSE23 BRIDGEPORT_BRIDGEPORT	9	19	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	9975
9		GRANT FUSE23 BRIDGEPORT_DIXIE LCP 383_93	2	1	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	525
10		GRANT FUSE23 BUCHANAN_SANDY SHORES*	11	13	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	6825
11		GRANT FUSE23 BURR OAK_INDUSTR LCP 628 29	2	1	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	525
12		GRANT FUSE23 BUSCH ROAD_CANADA	3	4	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	2100
13		GRANT FUSE23 BYRON CENTER_CAR LCP 974_33	2	1	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	525
14		GRANT FUSE23 CARLETON RD_BECK LCP 567 25	2	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
15		GRANT FUSE23 CARLETON RD_BECK LCP 567 27	2	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
16		GRANT FUSE23 CEDAR LAKE_KINGS CORNER	43	26	Fuses	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	13650
17		GRANT FUSE23 CHESANING_CHESANI LCP 624 1	1	3	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	1575
18		GRANT FUSE23 CLARKSVILLE_CLARKSVILLE 2	10	13	Fuses	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	6825
19		GRANT FUSE23 COLON_PALMER LCP LCP 765 1	3	2	Fuses	Zonal Health Improvements	ST JOSEPH	Customer-outage-minutes avoided	1050
20		GRANT FUSE23 DEWEY_WIDDICOMB L LCP SUB 1	2	3	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1575
21		GRANT FUSE23 DOBSON ROAD_HALF MOON	34	26	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	13650
22		GRANT FUSE23 E GENESEE AVE_BA LCP SUB_28	2	5	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	2625
23		GRANT FUSE23 FILLMORE_NORTH BLENDON 1-7	5	5	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	13650
24		GRANT FUSE23 FOREST GROVE_GREE LCP SUB 1	7	4	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	2100
25		GRANT FUSE23 FRANKENMUTH_DEHMEL	3	2	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	1050
26		GRANT FUSE23 GILSON_WYMAN	77	19	Fuses	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	9975
27		GRANT FUSE23 GIRARD_GIRARD	21	18	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	9450
28		GRANT FUSE23 GLEN LK_HOMESTEA LCP 933 37	3	1	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	525
29		GRANT FUSE23 GOODALE_ROOSEVELT	17	21	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	11025
30		GRANT FUSE23 GRAYLING_BEAR	9	5	Fuses	Zonal Health Improvements	CRAWFORD	Customer-outage-minutes avoided	2625
31		GRANT FUSE23 HAMMOND RD_AIRPOR LCP 001_2	2	1	Fuses	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	525
32		GRANT FUSE23 HARPER ROAD_ARENS	4	6	Fuses	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	3150
33		GRANT FUSE23 KINGSLEY_WALTON 56	1	1	Fuses	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	525
34		GRANT FUSE23 LAUNDRA_PLEASANTV LCP 515 4	2	1	Fuses	Zonal Health Improvements	BAY	Customer-outage-minutes avoided	525
35		GRANT FUSE23 LITCHFIELD_QUAKER LAKE	34	32	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	16800
36		GRANT FUSE23 MAPLE CTY_CEDAR L LCP 120 2	3	2	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	1050
37		GRANT FUSE23 MAPLE CTY_CEDAR LCP 061 56	2	1	Fuses	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	525
38		GRANT FUSE23 MAPLE CTY_CEDAR LCP 068 49	2	1	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	525
39		GRANT FUSE23 MAPLE CTY_CEDAR LCP 5359 69	2	1	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	525
40		GRANT FUSE23 MAPLE CTY_CEDAR LCP 728 87	3	2	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	1050
41		GRANT FUSE23 MAPLE CTY_CEDAR LCP 745 23	4	2	Fuses	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	1050
42		GRANT FUSE23 MCKEIGHAN_SHARON LOC 1-20	50	36	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	18900
43		GRANT FUSE23 MEDICAL PK_HEALTHCARE VILLA	8	4	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	2100
44		GRANT FUSE23 MULLINS_MULLINS	2	1	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	525
45		GRANT FUSE23 NEWBURG_BANCROFT LCP 300 9	1	2	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	1050
46		GRANT FUSE23 NEWBURG_VERNON	4	7	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	3675
47		GRANT FUSE23 NORTH CORUNNA_COPAS ROAD	2	4	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	2100
48		GRANT FUSE23 NORTH CORUNNA_MEIJER	10	16	Fuses	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	8400
49		GRANT FUSE23 O-AT-KA_EAST BAY	7	23	Fuses	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	12075
50		GRANT FUSE23 OVID_OVID	15	29	Fuses	Zonal Health Improvements	CLINTON	Customer-outage-minutes avoided	15225
51		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**458**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 8 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	GRANT FUSE23 PEARLINE_WINDFIEL LCP 522 2	2	1	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	525
2		GRANT FUSE23 PECK RD_M-91 LCP LCP 112_9	2	1	Fuses	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	525
3		GRANT FUSE23 PIGEON LAKE_PIGEON	20	16	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	8400
4		GRANT FUSE23 RANKIN_TRAPANI LC LCP 356 1	2	2	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	1050
5		GRANT FUSE23 READING_CTY LCP 8 LCP 869 8	10	6	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	3150
6		GRANT FUSE23 RUSSELL ROAD_RUSSELL ROAD	24	40	Fuses	Zonal Health Improvements	LENAWEE	Customer-outage-minutes avoided	21000
7		GRANT FUSE23 SIMMONS_DAM ROAD SECTION 1	651	139	Fuses	Zonal Health Improvements	OGEMAW	Customer-outage-minutes avoided	72975
8		GRANT FUSE23 SINCLAIR_HERITAGE LCP SUB 1	2	2	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1050
9		GRANT FUSE23 SINCLAIR_HERITAGE LCP SUB 2	2	1	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	525
10		GRANT FUSE23 SPICEBUSH_LACOTA PART 1	289	29	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	15225
11		GRANT FUSE23 SQUIRES_ALLEN	28	14	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	7350
12		GRANT FUSE23 SQUIRES_PACKING	14	6	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	3150
13		GRANT FUSE23 ST CHARLES_SAGINAW*	23	38	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	19950
14		GRANT FUSE23 STADIUM_COLLEGE LCP 304 1	6	4	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	2100
15		GRANT FUSE23 STANDALE_STANDALE LCP SUB 1	2	1	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	525
16		GRANT FUSE23 STONEGATE_CHRISTIAN	11	9	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	4725
17		GRANT FUSE23 STURGEON_PERRINE	9	10	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	5250
18		GRANT FUSE23 TEKONSHA_WAGNER L LCP 619_9	3	1	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	525
19		GRANT FUSE23 WALNUT_GILKEY LC LCP 247 20	2	1	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	525
20		GRANT FUSE23 WALNUT_GILKEY LC LCP 379 18	2	1	Fuses	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	525
21		GRANT FUSE23 WATKINS_KNAPP	9	22	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	11550
22		GRANT FUSE23 WILDER_WILDER	38	23	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	12075
23		GRANT FUSE23 WILLIAMS_LINCOLN 2	9	16	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	8400
24		GRANT INSP22 BARNARD_HOSPITAL LCP 713_5	2	1	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	525
25		GRANT INSP22 FRONTIER_TAMARAC LCP 610_19	1	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
26		GRANT INSP22 KOLASSA_MATTESON LCP 523_36	2	1	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	525
27		GRANT RLBY ALGER_FOREST LAKE LCP 802 OHL	987	1.87	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	439822
28		GRANT RLBY BALCOM_BANKERS LCP 578	92	0.25	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	494559
29		GRANT RLBY BEADLE SPAULDING 257 PT2	130	0.26	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	113460
30		GRANT RLBY Cedar Springs-Edg Sub OHLN-1	530	0.65	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	2073212
31		GRANT RLBY CHAUVEZ PARK LCP 302	384	1.3	Miles	Zonal Health Improvements	MASON	Customer-outage-minutes avoided	74732
32		GRANT RLBY HARRIETTA-MARILLA LCP 636 PT1	230	1	Miles	Zonal Health Improvements	WEXFORD	Customer-outage-minutes avoided	101,898
33		GRANT RLBY Honor/Indian Hill LCP6418 PT1	601	1	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	55,025
34		GRANT RLBY HUBBARD LK_MILLER RD 681 PT 1	1,501	3	Miles	Zonal Health Improvements	ALCONA	Customer-outage-minutes avoided	1191242
35		GRANT RLBY Joppa - Joppa LCP 854	208	0.5	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	173780
36		GRANT RLBY KENT CITY_CASNOVIA BLLCRK OHL	308	0.64	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	726472
37		GRANT RLBY MARION-GASCOM LCP 014 PT 1	336	1.2	Miles	Zonal Health Improvements	CLARE	Customer-outage-minutes avoided	264686
38		GRANT RLBY NESTROM S SHORE LCP 557 (1-7)	387	1.21	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	179313
39		GRANT RLBY NOBLE_WHITNEY LCP 558 SHEET 1	1,254	1.53	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	635878
40		GRANT RLBY SANDERSON_COUNTY FARM LCP 414	143	0.34	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	126259
41		GRANT RLBY TEXAS_EAGLE LAKE LCP 746	115	0.2	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	240985
42		GRANT RLBY18 AU GRES_AU GRES LCP 836	83	1	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	143060
43		GRANT RLBY20 Alder Creek E Leroy LCP 469	200	2.4	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	26738
44		GRANT RLBY21 GALESBRG-CHARLE LCP 453,478	564	0.64	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	61007
45		GRANT WLDFRE RYNO-MAPES LCP 5308	1,204	1.44	Poles	Zonal Health Improvements	OSCODA	Customer-outage-minutes avoided	22495
46		GRANT ZONE22- 12949 GRATIOT RD SAG	1	1	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	525
47		GRANT ZONE22 BARNARD.WEISS LCP LCP 690.1	1	10	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	5250
48		GRANT ZONE22 BARNARD_HOSPITAL LCP SUB_8.	4	6	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	2100
49		GRANT ZONE22 CAMDEN_CAMDEN LCP LCP 246_2	8	5	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	2625
50		GRANT ZONE22 CARLETON RD_BECK LCP SUB_1	35	21	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	11025
51		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**10,472**						

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($000)

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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	GRANT ZONE22 JONESVILLE_JONESV LCP 513_1	2	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
2		GRANT ZONE22 JONESVILLE_MILNES LCP 324_1	2	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
3		GRANT ZONE22 KOLASSA_KOSMERICK LCP 154_1	1	42	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	22050
4		GRANT ZONE22 LITCHFIELD_ADAMS LCP SUB_1	2	3	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	1575
5		GRANT ZONE22 LITCHFIELD_QUAKER LCP 516_1	1	2	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	1050
6		GRANT ZONE22 MENDON_KIRBY LCP LCP 528_3	6	3	Fuses	Zonal Health Improvements	ST JOSEPH	Customer-outage-minutes avoided	1575
7		GRANT ZONE22 MERRILL_CHAPIN L LCP SUB_54	1	1	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	525
8		GRANT ZONE22 MT PLEASANT_COLLE LCP 489_3	1	1	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	525
9		GRANT ZONE22 READING_CAMBRIA L LCP 618_2	3	2	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	1050
10		GRANT ZONE22 SHEPHERD_SHEPHERD LCP 225_1	2	1	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	525
11		GRANT ZONE22 WESTERN AVE_BARCL LCP 376_2	3	2	Fuses	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	1050
12		GRID - Elm St05_Princeton01	35	2	Poles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	336000
13		GRID - Olivet02_Bellevue02	95	1	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	285720
14		GRID ALAMO_ALAMO ATR LOOP	60	1	Project	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	137,972
15		GRID Babcock02_Kolassa02	15	0.25	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	443160
16		GRID BRETON02_BRETON05	57	1	project	Zonal Health Improvements	KENT	Service Quality; number of customers	131
17		GRID CADILLAC01-CADILLAC02	33	1	Project	Zonal Health Improvements	WEXFORD	Customer-outage-minutes avoided	522600
18		GRID COOLEY02_COOLEY02	135	1	Project	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	257040
19		GRID DEWEY01_DEWEY02	88	5	Poles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	787680
20		GRID EAST GENESEE AVE/OUTER DRIVE_GENESE	78	4	Poles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	3127
21		GRID EAST MUSKEGON01_APPLE04	211	1	Project	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	1028000
22		GRID ELEVENTH ST01_ALAMO03	75	1	Project	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	626040
23		GRID Fellowship03	24	1	Project	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	209760
24		GRID Goguac03	30	2	Poles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	1725780
25		GRID KEATING01_KEATING02	400	1	Project	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	2158579
26		GRID KENDALL02_DRAKE RD06	60	1	Project	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	463440
27		GRID KENTWOOD04_BROADMOOR05	54	1	Project	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	871200
28		GRID PHILLIPS04_OAKWOOD03	78	1	Project	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	523200
29		GRID ROGUE RIVER01_HULL STREET02	12	1	Project	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	55105
30		GRID ROGUE RIVER02_ROCKFORD FRESKA LK02	47	1	Project	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	81053
31		GRID SHIELDS/SHIELDS_SHATTUCK/FOX GLEN	48	1	Project	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	1005
32		GRNT RLBY ALAMO_PINE GROVE LCP 638 UGL 1	1,347	2.15	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	412900
33		HZRD ANGELL-ELK-MORRISON LCP 651	22	0.21	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	9360
34		HZRD ANTRIM-ELK RAPIDS LCP 705	32	0.33	Miles	Zonal Health Improvements	ANTRIM	Customer-outage-minutes avoided	22860
35		HZRD BALDWIN IDLEWILD LCP 062	202	1	Miles	Zonal Health Improvements	LAKE	Customer-outage-minutes avoided	5549
36		HZRD BALDWIN IDLEWILD LCP 146T	210	1	Miles	Zonal Health Improvements	LAKE	Customer-outage-minutes avoided	5549
37		HZRD BATES-ACME LCP 411	39	0.4	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	825
38		HZRD CHESANING/OAKLEY LCP 383 - 8C	20	0.14	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	8
39		HZRD HONOR-INDIAN HILL LCP 167	93	0.17	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	540
40		HZRD INTERLOCHEN-ART CAMP LCP 892	25	0.07	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	1620
41		HZRD INTERLOCHEN-COPEMISH LCP 981	22	0.12	Miles	Zonal Health Improvements	MANISTEE	Customer-outage-minutes avoided	2160
42		HZRD LEELANAU-BELANGER CREEK LCP 7002	14	0.05	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	360
43		HZRD LEELANAU-OMENA BAY LCP 679	25	0.13	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	21548
44		HZRD LEELANAU-OMENA BAY LCP 9022	67	0.42	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	3804
45		HZRD LELAND-LELAND KILWY RD	39	0.15	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	540
46		HZRD LELAND-LELAND LCP 9656	41	0.15	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	665
47		HZRD MAPLE CITY-CEDAR LCP 0009	120	0.5	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	540
48		HZRD NORTHPORT-LIGHTHOUSE LCP 6032	150	0.52	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	7200
49		HZRD NORTHPORT-MANITOU LCP 342	41	0.23	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	720
50		HZRD NORTHPORT-MANITOU LCP 6410	85	0.24	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	7161
51		HZRD NUNICA-WILSON LCP 643	67	0.2	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	2880
52		HZRD PENINSULA-MCKINLEY ROAD LCP 535	19	0.09	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	39672
53		HZRD PENINSULA-MCKINLEY ROAD LCP 7104	20	0.13	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	900
54		HZRD SILVER LAKE-SECOR LCP 5432	20	0.11	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	540
55		HZRD VIPOND-BROOK LCP 551	10	0.01	Miles	Zonal Health Improvements	KALKASKA	Customer-outage-minutes avoided	1080
56		OHL RLBY REED CITY_MEDICAL LCP 668	611	0.47	Miles	Zonal Health Improvements	OSCEOLA	Customer-outage-minutes avoided	294000
57		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**4,996**						

MICHIGAN PUBLIC SERVICE COMMISSION
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($000)

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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE15 Alder Creek / Lee Lake #15	5	5	Poles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	420
2		POLE18 DELTON/DELTON-LCP 782 PT2	66	22	Poles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	4,228
3		REHAB16 BROADMOOR 36TH ST. LCP 715	6	0.01	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	960
4		REHAB16 OWOSSO-BUSINESS PHASE 4 REMOVEAL	33	0.2	Miles	Zonal Health Improvements	SHIAWASSEE	Customer-outage-minutes avoided	14000
5		REHAB19 MAGNUS MCKAY FARM LCP 865 Pt 1	575	2	Miles	Zonal Health Improvements	CLARE	Service Quality; number of customers	50
6		RLBY - Bellevue Assyria 257 Part 1	383	1.03	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	15633
7		RLBY ALAMO_PINE GROVE LCP 89	156	0.25	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	39822
8		RLBY Alder Creek - E Leroy LCP 661	150	1	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	129460
9		RLBY ALGER_FOREST LAKE LCP 076	131	0.7	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	16485
10		RLBY AU GRES_AU GRES LCP544 PART 1	851	1.75	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	241911
11		RLBY BALDWIN BALDWIN LCP 113	125	0.46	Miles	Zonal Health Improvements	LAKE	Customer-outage-minutes avoided	65,274
12		RLBY Belding_Mall OH - LOC 1-29	948	0.6	Miles	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	84000
13		RLBY BELLEVUE_ASSYRIA 007 PT. 1	1,489	1.6	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	75906
14		RLBY BRONSON MILL ST 334 Part 1	2,002	1.5	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	174138
15		RLBY BULLOCK PRAIRIE LCP 722	249	1	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	28,927
16		RLBY CANNONSBURG-GRASS LAKE SUNFISH L	187	0.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	76203
17		RLBY CANONSBURG_WEST CANNON LCP-317	416	0.9	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	116269
18		RLBY CRYSTAL_MT HOPE ROAD LCP 438	128	0.55	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	105091
19		RLBY DEAN ROAD_PARSHALLVILLE LCP 862 Pt1	531	0.8	Miles	Zonal Health Improvements	LIVINGSTON	Customer-outage-minutes avoided	1608928
20		RLBY DIXIE SUB NEW CKT	75	0.3	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	172193
21		RLBY EAST GENESEE AVE/GENESEE PART 1	55	0.35	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	152964
22		RLBY EAST MUSKEGON_QUARTERLINE PT1	251	0.44	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	231477
23		RLBY Easton Parmeter LCP 424	50	0.25	Miles	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	1926
24		RLBY Elm St - Porter PHASE 2 ESIC OHL_2	111	1	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	808422
25		RLBY FOURTEENTH-SOUTHWESTERN ATR LOOP	243	0.58	Miles	Zonal Health Improvements	GENESEE	Customers	1,745
26		RLBY HARPER ROAD_ARENS LCP 363	228	0.75	miles	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	82,095
27		RLBY HOGAN ROAD_ROLSTON LCP sub	24	3	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	915088
28		RLBY Homestead Beulah LCP 0195 PH1 PT 1	147	0.82	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	65831
29		RLBY Homestead Beulah LCP 0195 PH2	333	2	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	175,480
30		RLBY HOMESTEAD_BEULAH LCP 734 Part 1	490	0.82	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	45692
31		RLBY JONESVILLE_MILNES LCP 390	95	0.75	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	44917
32		RLBY KRAFT AVENUE CENTENNIAL LCP 204	198	0.18	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	39015
33		RLBY LABARGE ALASKA 68th St LCP 208 1-12	835	1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	13474
34		RLBY LaBarge Blodgett Lake First Zone	49	0.75	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	375907
35		RLBY LAKE ODESSA LAKE LCP 585	93	1	Miles	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	100,871
36		RLBY LEITH STREET_WESTERN ROAD	150	5	Poles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	299219
37		RLBY MANCELONA_ALBA LCP 083	40	0.4	Miles	Zonal Health Improvements	ANTRIM	Customer-outage-minutes avoided	36170
38		RLBY MCCANDLISH_BUSH CREEK LCP 767	7	2	Fuses	Zonal Health Improvements	GENESEE	Customers	48
39		RLBY MERSON_DUCK LAKE LCP 847	75	0.22	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	179086
40		RLBY MIDDLEVILLE_BUSINESS LCP 037	400	0.94	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	340274
41		RLBY Midland Buttles	185	0.34	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	67700
42		RLBY MILLGROVE_ALLEGAN HYDRO 993 PT1 OHL	284	1.5	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	163438
43		RLBY MILLGROVE_ALLEGAN HYDRO LCP SUB 1	385	1.52	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	790836
44		RLBY NESTROM SCENIC DRIVE LCP 343	266	0.95	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	40093
45		RLBY NESTROM SOUTH SHORE LCP 693	25	0.07	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	85297
46		RLBY Northport Lighthouse LCP 598 Part A	295	1	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	116,584
47		RLBY OTSEGO_FARMER 830 and 832 Part 1	698	1	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	238511
48		RLBY SCIPIO-MOSHERVILLE-WINFIELD-TW	70	0.21	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	1108607
49		RLBY SLOAN LONGFELLOW ATR LOOP	352	0.3	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	2000
50		RLBY SPRING ARBOR_ARBOR HILLS	231	0.2	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	376190
51		RLBY TURNER_GATES DYER RD	200	1	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	85800
52		RLBY VIRGINIA PARK_MACATAWA ATR LOOP	325	1.11	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	254075
53		RLBY WARNER-BURCHETT LCP 315	130	0.45	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	326113
54		RLBY WEST FENTON-FENTON NOVA	90	0.1	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	3860
55		RLBY WIRTZ ROAD_WILDWOOD LCP 309 SHT 1	1,232	2	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	135032
56		RLBY14 KRAFT AVENUE/TAHOE. LCP 260	126	0.27	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	13206
57		RLBY14 KRAFT AVENUE/TAHOE. LCP 260 PH2	84	0.2	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	13206
58		RLBY15SCIPIO-MOSHERVILLE-GOOSELK-TW	95	0.28	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	1108607
59		RLBY16 ALDER CREEK/LEE LAKE PHASE 2 PT 1	61	0.98	Miles	Zonal Health Improvements	CALHOUN	Customers	44
60		RLBY16 SPICEBUSH_LESTER LAKE ORDER01	392	0.4	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	813743
61		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**17,904**						

MICHIGAN PUBLIC SERVICE COMMISSION
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Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

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Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	RLBY17 CONVIS_CONVIS 304 PART B	66	0.43	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	220654
2		RLBY17 COOKE DAM/SUB MONUMENT PUT IN SVC	0	0.1	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	349860
3		RLBY17 FOOTE HYDRO_REA RD SUB (NEW)	105	0.25	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	22910
4		RLBY17 HOLTON/HOLTON LCP 488 part 7	97	1.2	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	175,541
5		RLBY17 MARTIN_SHELBYVILLE LCP 212	80	0.35	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	14278
6		RLBY17BURROWS/GRATIOT LCP725 Golfside-OH	99	0.78	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	104
7		RLBY18 Freeland/Freeland LCP 922 Part 1	487	1.4	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	87778
8		RLBY18 Homestead/Beulah LCP 5833	258	0.13	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	12209
9		RLBY18 LAWRENCE_CHRISTIE LAKE LCP653 Pt1	1,105	1.04	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	117803
10		RLBY18 POTTERVILLE/M-78 RELOC ROYSTON RD	164	0.5	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	185188
11		RLBY19 FROST LONG LK LCP 267	394	1	Miles	Zonal Health Improvements	CLARE	Customer-outage-minutes avoided	34604
12		RLBY19 GERRISH SUB RECONDUCTOR 4A	795	2	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	163,120
13		RLBY19 HARRISON STOCKWELL LCP 114 HZD	94	0.3	Miles	Zonal Health Improvements	CLARE	Customer-outage-minutes avoided	19,132
14		RLBY19 READING_CAMBRIA LCP 603 PT 1	108	0.49	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	3554851
15		RLBY19CAMBRIDGE-IRISHHILLS-RCND #2 M50 1	865	2.33	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	3131944
16		SAFETY21 QUINCY_BLACKHAWK	100	0.28	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	41860
17		SECT15 FENTON/ DENTON HILL & SILVER LAKE	28	1	Project	Zonal Health Improvements	GENESEE	System Protection Improvement; Customers	2298
18		SYSP ITHACA_FAIR GROUNDS LCP 307	8	1	Project	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	16,355
19		SYSP STARKS_HOMER LCP 642	3	1	Project	Zonal Health Improvements	MIDLAND	Customers	10
20		SYSP19 BELDING COOKS CORNER LCP 196	23	1	Project	Zonal Health Improvements	IONIA	System Protection Improvement; Customers	39
21		SYSP19 INgersoll_Sasse LCP 005	25	1	Project	Zonal Health Improvements	MIDLAND	System Protection Improvement; Customers	1575
22		VOLT - Bellevue Bellevue 082	135	17	Poles	Zonal Health Improvements	EATON	Service Quality; number of customers	27
23		VOLT 048204 - 1439 LINDBURGH	8	1	Project	Zonal Health Improvements	CHEBOYGAN	Customers	14
24		VOLT 048204-6571 ORCHARD BEACH DR	23	1	Project	Zonal Health Improvements	CHEBOYGAN	Customers	9
25		VOLT 048204-7491 MCDONALD RD	18	1	Project	Zonal Health Improvements	CHEBOYGAN	Customers	8
26		VOLT 048204-BEEBE RD MTRS ESIC	16	1	Project	Zonal Health Improvements	CHEBOYGAN	Customers	2
27		VOLT BISHOP-RAINBOW	55	3	Poles	Zonal Health Improvements	GENESEE	Service Quality; number of customers	44
28		VOLT CASCADE_PEACE STREET LCP 0761	12	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	11
29		VOLT DEWITT_DEWITT LCP 497	16	1	Poles	Zonal Health Improvements	CLINTON	Service Quality; number of customers	1
30		VOLT DEWITT-HOWE RD LCP162 1 OF 2	466	1	Miles	Zonal Health Improvements	CLINTON	Service Quality; number of customers	121
31		VOLT FENNVILLE_COMMERCIAL LCP SUB	75	0.3	Miles	Zonal Health Improvements	ALLEGAN	Service Quality; number of customers	38
32		VOLT GILKEY CREEK/WALKER LCP 738	220	0.5	Miles	Zonal Health Improvements	GENESEE	Service Quality; number of customers	0
33		RLBY WILDWOOD_MACKLIN SUB	159	0.3	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	199440
34		RLBY AUBIL LAKE_TOWERS LCP 647	450	1.3	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	213057
35		GRANT RLBY Kellogg svl/Kellogg svl LCP 084	170	0.75	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	227742
36		VOLT Kearsley/Covert ESIC OHL	172	5	Poles	Zonal Health Improvements	GENESEE	Service Quality; number of customers	109
37		GRANT RLBY MERSON MERSON LCP 420	700	1.26	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	229494
38		VOLT Lee St_Kirtland	110	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	129
39		GRID HASTINGS02_RUTLAND02	45	1	Project	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	230160
40		VOLT LOOMIS_TAFT ROAD LCP 236	16	1	Project	Zonal Health Improvements	CLINTON	Service Quality; number of customers	40
41		RLBY NORTH PARK_LAMBERTON RECONDUCTOR	449	1.04	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	261784
42		RLBY Rockford/Summit LCP-565	245	0.52	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	265445
43		GRID MUSKEGON HEIGHTS02_KEATING01	184	4	Poles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	276000
44		GRANT RLBY19 BITTERSWEET_RIVER RD LCP330	600	1.33	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	282111
45		RLBY HULL STREET_LIME LAKE LCP-888	408	1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	282390
46		GRANT RLBY Lefingwel_BradfordEB TreeWire	250	0.5	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	300400
47		GRANT RLBY PIGEON LAKE_PIGEON LCP CKT	660	0.78	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	316278
48		RLBY19 ENGLISHVILLE/PINE ISLAND LCP-505	487	0.88	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	323011
49		GRID Goguac01	75	1	Project	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	331440
50		GRID MUSKEGON HEIGHTS05_KEATING01	230	6	Poles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	359280
51		GRANT RLBY CDR SPRING_EDGERTON LCP 814-1	806	1.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	419401
52		GRANT RLBY CEDAR SPRINGS_NELSON LCP 179	496	0.78	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	459565
53		GRID Kinderhook01_Behnke01	15	0.25	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	471040
54		RLBY Cascade Thorncrest LCP 913	347	0.45	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	479194
55		GRID HAGER PARK02_ROSEWOOD02	20	2	Poles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	491880
56		BKBNP14 PALMER REED 1	42	11	Poles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	496440
57		Rockford Sub UG Cable Replacement - UGLN	483	0.35	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	604,770
58		RLBY - Convis Convis SUB	150	0.13	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	615000
59		VOLT PHILLIPS_INKSTER HECO	354	0.91	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1243
60		GRID STANLEY01_DIXIE03	95	1	Project	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	652578
61		GRID Centreville02_BurrOak02	15	0.25	Miles	Zonal Health Improvements	ST JOSEPH	Customer-outage-minutes avoided	782520
62		RLBY ALAMO_FISH HATCHERY LCP CKT	490	1.16	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	1019469
63		RLBY PARAMOUNT-NORTHLAND FARMS LCP-137	829	1.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1051380
64		VOLT Shepherd_Shepherd LCP 234	25	4.88	Miles	Zonal Health Improvements	ISABELLA	Service Quality; number of customers	54
65		RLBY Leffingwell/Nottingham EB & Cascade	716	1.58	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1104262
66		GRID HAGER PARK02_CHICAGO02	43	4	Poles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	1524100
67		VOLT STANDISH_STANDISH LCP 827	495	2.22	Miles	Zonal Health Improvements	ARENAC	Service Quality; number of customers	165
68		VOLT PARKWAY VINE 4109	32	1	Project	Zonal Health Improvements	KALAMAZOO	Customers	23
69		VOLT STATE STREET_MACKINAW LCP 684J	28	3	Poles	Zonal Health Improvements	SAGINAW	Service Quality; number of customers	75
70		VOLT19 SUNFIELD-MULLIKEN--FINAL	433	1	Project	Zonal Health Improvements	EATON	Service Quality; number of customers	1,032
71		VOLT23 HOUGHTN PRDNVILLE	66	3	Poles	Zonal Health Improvements	ROSCOMMON	Service Quality; number of customers	346
72		ZONE22 ASH ROAD_STERLING ROAD LCP SUB_1	1	9	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	4725
73		ZONE22 BRADFORD_DISTRIB LCP 049_9.	1	1	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	525
74		ZONE22 BURR OAK_INDUSTRIAL LCP 218_1	2	33	Fuses	Zonal Health Improvements	ST JOSEPH	Customer-outage-minutes avoided	17325
75		ZONE22 CAMDEN_CAMDEN LCP 246_4	2	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
76		ZONE22 JONESVILLE_MILNES LCP 356_1	4	3	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	1575
77		ZONE22 RAMONA_ROBINSON LCP 496_2	2	1	Fuses	Zonal Health Improvements		Customer-outage-minutes avoided	525
78		ZONE22 READING_CAMBRIA LCP 674_1	2	1	Fuses	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	525
79		ZONE22 ST CHARLES_SAGINAW LCP SUB_53.	3	1	Fuses	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	525
80		ZONE22 STARKS_LEE LCP SUB_1	2	1	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	525
81		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**17,354**						
82		**Zonal Health Improvements Total**	**61,320**						

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($000)

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Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	SCDY Michigan/Lookout	690	2.30	Miles	Secondary	GRAND RAPIDS	Service Quality; number of customers	64
2		SCDY Eastwood/Texel	3,690	12.30	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	1,454
3		SCDY Red Arrow/Keats	2,250	7.50	Miles	Secondary	FLINT	Service Quality; number of customers	187
4		SCDY Beecher/Anderson	600	2.00	Miles	Secondary	ADRIAN	Service Quality; number of customers	331
5		SCDY Summit/Francis Street	1,590	5.30	Miles	Secondary	JACKSON	Service Quality; number of customers	740
6		SCDY Liberty/Hamblin	2,100	7.00	Miles	Secondary	SPRINGFIELD	Service Quality; number of customers	532
7		SCDY Kendall/Westwood	1,890	6.30	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	727
8		SCDY Oakwood/Parkview	1,260	4.20	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	421
9		SCDY Aberdeen/Hollywood	2,940	9.80	Miles	Secondary	GRAND RAPIDS	Service Quality; number of customers	1,553
10		SCDY Summit/South Street	900	3.00	Miles	Secondary	JACKSON	Service Quality; number of customers	279
11		SCDY Bridge Street/Water Street	900	3.00	Miles	Secondary	JACKSON	Service Quality; number of customers	59
12		SCDY Maple Grove/Summit	750	2.50	Miles	Secondary	MUSKEGON	Service Quality; number of customers	277
13		SCDY Muskegon Heights/E Central	120	0.35	Miles	Secondary	MUSKEGON	Service Quality; number of customers	31
14		**LVD Lines Reliability Subtotal (Secondary Total)**	**19,680**						
15		UINJ Cable Rejuvenation Flint	11,596	28.00	Miles	Underground Cable Rejuvenation	Flint Area	Customer-outage-minutes avoided	638,620
16		UINJ Cable Rejuvenation Grand Rapids	11,495	28.00	Miles	Underground Cable Rejuvenation	Grand Rapids Area	Customer-outage-minutes avoided	633,058
17		UINJ Cable Rejuvenation Traverse City	4,818	12.00	Miles	Underground Cable Rejuvenation	Traverse City Area	Customer-outage-minutes avoided	265,339
18		**LVD Lines Reliability Subtotal (Underground Cable Total)**	**27,909**						
19		RLBY Stanwood-Riversway Ph 3 - Part 1	3,476	13.00	Miles	Voltage Conversions	MECOSTA	Customer-outage-minutes avoided	525,008
20		RLBY Stanwood-Tyler Rd Volt Conv	180	1.90	Miles	Voltage Conversions	MECOSTA	Customer-outage-minutes avoided	3409
21		RLBY17 BREEDSVILLE_GRAND JUNCTION 941	225	0.60	Miles	Voltage Conversions	VAN BUREN	Customer-outage-minutes avoided	27071
22		RLBY19 GERRISH SUB VOLT CONV 7 LOC 36-63	156	0.71	miles	Voltage Conversions	ROSCOMMON	Customer-outage-minutes avoided	45980
23		RLBY19 GERRISH SUB VOLT CONV 7 LOC 63-78	156	0.42	Miles	Voltage Conversions	ROSCOMMON	Customers	17
24		RLBY19 GERRISH SUB VOLTAGE CONVERSION 2	498	3.92	Miles	Voltage Conversions	ROSCOMMON	Customer-outage-minutes avoided	318084
25		RLBY19 GERRISH SUB VOLTAGE CONVERSION 2a	99	0.65	Miles	Voltage Conversions	CRAWFORD	Customer-outage-minutes avoided	15047
26		RLBY19 GERRISH SUB VOLTAGE CONVERSION 3	690	3.89	Miles	Voltage Conversions	CRAWFORD	Customer-outage-minutes avoided	15,047
27		RLBY19 GERRISH SUB VOLTAGE CONVERSION 5	137	0.31	miles	Voltage Conversions	ROSCOMMON	Customer-outage-minutes avoided	280125
28		RLBY19 GERRISH SUB VOLTAGE CONVERSION 6	126	3.52	Miles	Voltage Conversions	ROSCOMMON	Customer-outage-minutes avoided	-
29		RLBY19 GERRISH SUB, VOLT CONVERS 1, SH 1	1,718	12.20	Miles	Voltage Conversions	CRAWFORD	Customer-outage-minutes avoided	2,031,417
30		RLBY21 EIGHT POINT LK GEORGE LCP 861 Pt1	966	3.00	Miles	Voltage Conversions	CLARE	Customer-outage-minutes avoided	254911
31		**LVD Lines Reliability Subtotal (Voltage Conversion Total)**	**8,427**						
32		**LVD Lines Reliability Subtotal**	**112,033**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	EXIT AGNEW SUB EXIT SW	19	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
2		EXIT ASHMAN CIRCLE_ASHMAN	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
3		EXIT ASHMAN CIRCLE_SUGNET	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
4		EXIT ATLAS SUB	14	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
5		EXIT BABCOCK	13	1	Project	Circuit Exit Projects	BRANCH	Increase Safety by Installing Isolation Point	-
6		EXIT BARNUM	39	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
7		EXIT BELSAY SUB	9	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
8		EXIT BOSTON SQUARE/MULICK PARK CKT 4	11	1	Poles	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
9		EXIT BRYE RD SUB SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	MASON	Increase Safety by Installing Isolation Point	-
10		EXIT CALKINS SUB	50	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
11		EXIT CALVIN SUB	28	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
12		EXIT CASCADE THORNCREST	11	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
13		EXIT CENTREVILLE	26	1	Project	Circuit Exit Projects	ST JOSEPH	Increase Safety by Installing Isolation Point	-
14		EXIT CHICAGO SUB SWITCHES	64	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
15		EXIT CLIMAX	39	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
16		EXIT Conklin Park Sub	19	1	Project	Circuit Exit Projects	NEWAYGO	Increase Safety by Installing Isolation Point	-
17		EXIT CRANBROOK	32	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
18		EXIT CURTIS_MAGRUDDER	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
19		EXIT DALE ROAD_BEAR CREEK	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
20		EXIT DALE ROAD_M-18	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
21		EXIT DAVENPORT_CONGRESS	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
22		EXIT DAVISON SUB	12	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
23		EXIT DEER LAKE_BALL AVENUE	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
24		EXIT DEER LAKE_CRANBERRY LAKE	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
25		EXIT DUNHAM SUB	50	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
26		EXIT GENESEEVILLE SUB	30	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
27		EXIT GILSON_ROCK LAKE	9	1	Project	Circuit Exit Projects	MONTCALM	Increase Safety by Installing Isolation Point	-
28		EXIT GILSON_WYMAN	9	1	Project	Circuit Exit Projects	MONTCALM	Increase Safety by Installing Isolation Point	-
29		EXIT GLADWIN_CEDAR	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
30		EXIT GLADWIN_RURAL	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
31		EXIT GRANDVILLE SUB EXIT SWITCHES	13	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
32		EXIT HAMMOND ROAD SUB EXIT SWITCHES	24	1	Project	Circuit Exit Projects	GRAND TRAVERSE	Increase Safety by Installing Isolation Point	-
33		EXIT HARRISON_DODGE CITY	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
34		EXIT HARRISON_HARRISON	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
35		EXIT HARRISON_LILLEY LAKE	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
36		EXIT HARRISON_STOCKWELL	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
37		EXIT HUBBARD LAKE_SUB	25	1	Project	Circuit Exit Projects	ALCONA	Increase Safety by Installing Isolation Point	-
38		EXIT IRISH ROAD SUB	11	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
39		EXIT KEARSLEY SUB	50	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
40		EXIT LAKE LEANN SUB	35	3	Poles	Circuit Exit Projects	HILLSDALE	Increase Safety by Installing Isolation Point	-
41		EXIT LEFFINGWELL/ALL CKTS EXIT DIS	16	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
42		EXIT LEONARD_IONIA & TAYLOR	19	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
43		EXIT LESLIE SUB	26	1	Project	Circuit Exit Projects	INGHAM	Increase Safety by Installing Isolation Point	-
44		EXIT LYON MANOR SUB EXIT SWITCHES	8	1	Project	Circuit Exit Projects	ROSCOMMON	Increase Safety by Installing Isolation Point	-
45		EXIT MACATAWA	32	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
46		EXIT MANISTEE SUB SWITCHES	77	4	Poles	Circuit Exit Projects	MANISTEE	Increase Safety by Installing Isolation Point	-
47		EXIT MANNSIDING_CEDAR	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
48		EXIT MANNSIDING_MANNSIDING	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
49		EXIT McCracken Sub Exits	76	6	Poles	Circuit Exit Projects	MUSKEGON	Increase Safety by Installing Isolation Point	-
50		EXIT MIDLAND_BUTTLES	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
51		EXIT MIDLAND_COMMERCIAL	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
52		EXIT MILBOURNE SUB	50	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
53		EXIT MONTROSE SUB	50	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
54		EXIT NEELEY	18	1	Project	Circuit Exit Projects	ALLEGAN	Increase Safety by Installing Isolation Point	-
55		EXIT NIAGARA/ANDRE	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
56		EXIT OBERLIN_BENMARK	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
57		EXIT OBERLIN_MERIDITH	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
58		EXIT OSCODA_OSCODA	9	1	Project	Circuit Exit Projects	IOSCO	Increase Safety by Installing Isolation Point	-
59		EXIT PALMER	31	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
60		EXIT PENINSULA SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	GRAND TRAVERSE	Increase Safety by Installing Isolation Point	-
61		EXIT SHATTUCK/FOX GLEN	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
62		EXIT SQUIRE HILL SUB	50	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
63		EXIT ST CHARLES/SAGINAW	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
64		EXIT STARKS_HOMER	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
65		EXIT STARKS_LEE	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
66		EXIT SUMMIT SUB	10	1	Project	Circuit Exit Projects	JACKSON	Increase Safety by Installing Isolation Point	-
67		EXIT SURREY_MAIN STREET	9	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
68		EXIT Tinsman	8	1	Project	Circuit Exit Projects	OAKLAND	Increase Safety by Installing Isolation Point	-
69		EXIT VENICE SUB	50	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
70		EXIT WALNUT SUB	11	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
71		EXIT WHITEHALL SUB SUB EXIT SWITCHES	18	1	Project	Circuit Exit Projects	MUSKEGON	Increase Safety by Installing Isolation Point	-
72		EXIT WOOD STREET SUB	11	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
73		EXIT WOODWARD SUB EXIT SWITCHES	15	1	Project	Circuit Exit Projects	WEXFORD	Increase Safety by Installing Isolation Point	-
74		EXIT16 MAPLE GROVE HENRY STREET EXIT	70	1	Project	Circuit Exit Projects	MUSKEGON	Increase Safety by Installing Isolation Point	-
75		EXIT20 Mayfair/Mayfair & Sheraton	10	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
76		EXIT20 PICKEREL-EAST LAKE-UG	42	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
77		EXITS BURTCH ROAD	19	1	Project	Circuit Exit Projects	JACKSON	Increase Safety by Installing Isolation Point	-
78		EXITS CORUNNA_SUB	45	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
79		RLBY BYRON CENTER SUB EXIT SWITCHES	31	4	Poles	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
80		RLBY N MUSKEGON SUB EXIT SW	53	3	Poles	Circuit Exit Projects	MUSKEGON	Increase Safety by Installing Isolation Point	-
81		RLBY19 Haskelite_Richmond Ckt Exit Switc	19	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
82		RLBY20 PIGEON LAKE SUB Exit Switch	50	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
83		Stewart Rd Circuit Exit Owosso Sub	74	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
84		THDPY19 HUDSONVILLE SUB EXITS	13	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
85		**LVD Lines Reliability Subtotal (Circuit Exits Total)**	**1,911**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	DISTA HONOR01_GLEN LAKE02	1,314	1	Loop	Automation - ATR Loops	Benzie	Customer-outage-minutes-avoided	167424
2		GRANT DISTA AUBURN02_AUBURN01	746	1	Loop	Automation - ATR Loops	Bay	Customer-outage-minutes-avoided	62784
3		GRANT DISTA AUSTIN02_ZYLMAN02	341	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	75024
4		GRANT DISTA BALDWIN02_BALDWIN01	429	1	Loop	Automation - ATR Loops	Lake	Customer-outage-minutes-avoided	117120
5		GRANT DISTA BEHNKE01_QUINCY01	991	1	Loop	Automation - ATR Loops	Branch	Customer-outage-minutes-avoided	123552
6		GRANT DISTA BYRON CENTER02_RIVERTOWN01	722	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	74592
7		GRANT DISTA CAMELOT LAKE01_STARKS02	425	1	Loop	Automation - ATR Loops	Midland	Customer-outage-minutes-avoided	31872
8		GRANT DISTA CENTREVILLE01_CENTREVILLE02	106	1	Loop	Automation - ATR Loops	St Joseph	Customer-outage-minutes-avoided	68928
9		GRANT DISTA CHEYENNE01_STATE STREET01	367	1	Loop	Automation - ATR Loops	Saginaw	Customer-outage-minutes-avoided	64560
10		GRANT DISTA CONKLIN PK02_BIG PRAIRIE02	1,451	1	Loop	Automation - ATR Loops	Newaygo	Customer-outage-minutes-avoided	196512
11		GRANT DISTA COWAN LK02_HARVAR LK02	367	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	123648
12		GRANT DISTA DEWEY01_HASKELITE02	39	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	237312
13		GRANT DISTA DONTZ RD01_ONEKAMA01	469	1	Loop	Automation - ATR Loops	Manistee	Customer-outage-minutes-avoided	53424
14		GRANT DISTA DORR CORNERS02_BYRON CENTER04	742	1	Loop	Automation - ATR Loops	Allegan	Customer-outage-minutes-avoided	140976
15		GRANT DISTA EASTON02_EASTON01	20	1	Loop	Automation - ATR Loops	Ionia	Customer-outage-minutes-avoided	28944
16		GRANT DISTA EIGHT PT02_MANNSIDING01	122	1	Loop	Automation - ATR Loops	Clare	Customer-outage-minutes-avoided	29088
17		GRANT DISTA ELM STREET02_GOODALE03	567	1	Loop	Automation - ATR Loops	Calhoun	Customer-outage-minutes-avoided	117504
18		GRANT DISTA GETTY01_EAST MUSKEGON02	20	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	357696
19		GRANT DISTA GOODALE03_MORGAN01	367	1	Loop	Automation - ATR Loops	Calhoun	Customer-outage-minutes-avoided	32688
20		GRANT DISTA GRAND LEDGE04_GRAND LEDGE02	841	1	Loop	Automation - ATR Loops	Eaton	Customer-outage-minutes-avoided	175584
21		GRANT DISTA GRAND VALLEY01_STANDALE02	20	1	Loop	Automation - ATR Loops	Ottawa	Customer-outage-minutes-avoided	28944
22		GRANT DISTA HARRISON04_DEER LAKE02	469	1	Loop	Automation - ATR Loops	Clare	Customer-outage-minutes-avoided	103248
23		GRANT DISTA HARVEY ST06_RAMONA01	83	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	366840
24		GRANT DISTA HASKELITE04_FOUR MILE01	326	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	169248
25		GRANT DISTA HUDSONVILLE03_VAN BUREN01 (U)	226	1	Loop	Automation - ATR Loops	Ottawa	Customer-outage-minutes-avoided	27744
26		GRANT DISTA IVANREST01_BURLINGAME01	349	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	115620
27		GRANT DISTA JACKMAN03_JACKMAN01	726	1	Loop	Automation - ATR Loops	Monroe	Customer-outage-minutes-avoided	136320
28		GRANT DISTA KENDALL02_RAVINE02	347	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	104544
29		GRANT DISTA KILGORE04_OAKWOOD03	184	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	63600
30		GRANT DISTA LAKE LANSING02_PEACOCK02	492	1	Loop	Automation - ATR Loops	Ingham	Customer-outage-minutes-avoided	50400
31		GRANT DISTA LAMOREAUX01_WEST RIVER02	367	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	116112
32		GRANT DISTA LARKIN04_LARKIN02	485	1	Loop	Automation - ATR Loops	Midland	Customer-outage-minutes-avoided	155520
33		GRANT DISTA LINDEN02_HOGAN ROAD01	520	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	239424
34		GRANT DISTA MAPLE GROVE05_MUSKEGON HEIGHTS0	367	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	118272
35		GRANT DISTA MAUMEE02_HUNT ROAD03	1,033	1	Loop	Automation - ATR Loops	Lenawee	Customer-outage-minutes-avoided	249072
36		GRANT DISTA MILBOURNE03_HARRIET02	534	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	78912
37		GRANT DISTA MISSION01_BLUEGRASS01	27	1	Loop	Automation - ATR Loops	Isabella	Customer-outage-minutes-avoided	58944
38		GRANT DISTA MT MORRIS01_NEFF ROAD01	367	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	166944
39		GRANT DISTA MULLINS01_WALKER01	20	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	123696
40		GRANT DISTA MUSKEGON HEIGHTS02_KEATING01	367	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	259200
41		GRANT DISTA MUSKEGON HEIGHTS05_TERRACE02	367	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	29904
42		GRANT DISTA OAK STREET03_ROBERTS STREET01	367	1	Loop	Automation - ATR Loops	Jackson	Customer-outage-minutes-avoided	149568
43		GRANT DISTA OTTAWA BEACH01_MACATAWA03	242	1	Loop	Automation - ATR Loops	Ottawa	Customer-outage-minutes-avoided	108288
44		GRANT DISTA PEACH RIDGE02_KENT CITY02	20	1	Loop	Automation - ATR Loops	Kent	Customer-outage-minutes-avoided	282336
45		GRANT DISTA PHILLIPS02_PALMER04	245	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	152064
46		GRANT DISTA PHILLIPS04_PHILLIPS01	367	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	208944
47		GRANT DISTA POTTER01_JANES01	367	1	Loop	Automation - ATR Loops	Saginaw	Customer-outage-minutes-avoided	21984
48		GRANT DISTA QUINCY01_QUINCY03	409	1	Loop	Automation - ATR Loops	Branch	Customer-outage-minutes-avoided	116784
49		GRANT DISTA RIX ROAD02_OSHTEMO01	803	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	49440
50		GRANT DISTA ROBERTS ST02_EAST JACKSON01	865	1	Loop	Automation - ATR Loops	Jackson	Customer-outage-minutes-avoided	132768
51		GRANT DISTA SCIPIO02_HANOVER01	347	1	Loop	Automation - ATR Loops	Hillsdale	Customer-outage-minutes-avoided	60192
52		GRANT DISTA SHATTUCK01_LAUNDRA02	729	1	Loop	Automation - ATR Loops	Saginaw	Customer-outage-minutes-avoided	32544
53		GRANT DISTA SLOAN03_ALDRICH01	404	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	84816
54		GRANT DISTA STATE STREET03_BARNARD01	245	1	Loop	Automation - ATR Loops	Saginaw	Customer-outage-minutes-avoided	23232
55		GRANT DISTA TEKONSHA02_TEKONSHA01	1,085	1	Loop	Automation - ATR Loops	Calhoun	Customer-outage-minutes-avoided	83856
56		GRANT DISTA TEXAS01_TWELFTH ST01	592	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	103680
57		GRANT DISTA TRAVIS02_TWILIGHT02	20	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	27600
58		GRANT DISTA WEST FENTON03_FENTON02	367	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	167664
59		GRANT DISTA WESTERN AVENUE03_TERRACE01	20	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	212112
60		**LVD Lines Reliability Subtotal (ATR Loops Total)**	**25,616**						
61		**LVD Lines Reliability TOTAL**	**180,763**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA - Paris ave se, GR - SVLT	100	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
2	LVD Lines Rehabilitation	FA - POINTE RD HALE; OHC	6	1	Project	Imminent Rehabilitation	LOGAN	Correct Conductor Clearance Violation ; Customers	24
3	LVD Lines Rehabilitation	FA - EAST GENESEE AVE, SGN; BOVE	118	1	Project	Imminent Rehabilitation	SAGINAW	Relocate Electric With Structure Encroachment ; Customers	1
4	LVD Lines Rehabilitation	FA - EAST GENESEE, SGN; BOVE-OHS	1	1	Project	Imminent Rehabilitation	SAGINAW	Relocate Electric With Structure Encroachment ; Customers	1
5	LVD Lines Rehabilitation	FA - PLEASANT DR, SIX LAKES - SVLT	7	1	Project	Imminent Rehabilitation	LAKEVIEW	Improve Secondary Voltage ; Customers	5
6	LVD Lines Rehabilitation	FA - PORTADOWN SW BYRON CNTR - OHC	4	1	Project	Imminent Rehabilitation	BYRON	Correct Padmount to Building Clearance Violation ; Customers	1
7	LVD Lines Rehabilitation	FA - S NIAGARA ST, SAGINAW - OHC	3	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	20
8	LVD Lines Rehabilitation	FA - MILHAM AVE abandoned primary	18	1	Project	Imminent Rehabilitation	PORTAGE	Retire and Remove Unused Assets; Customers	58
9	LVD Lines Rehabilitation	FA - STARK ST, SAG; SVLT	63	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
10	LVD Lines Rehabilitation	FA - TH ST, ALLEGAN - SVLT	2	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Secondary Voltage ; Customers	5
11	LVD Lines Rehabilitation	FA - E REARDON ST, MDL; POL	9	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Pole ; Customers	242
12	LVD Lines Rehabilitation	FA - W HILL ST, PLAINWELL - SVLT	45	1	Project	Imminent Rehabilitation	PLAINWELL	Improve Secondary Voltage ; Customers	5
13	LVD Lines Rehabilitation	FA - W STANTON RD, PIERSON - POL	4	1	Project	Imminent Rehabilitation	PIERSON	Replace Deteriorated Pole ; Customers	242
14	LVD Lines Rehabilitation	FA - E COURT ST, FLINT - POL	7	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Pole ; Customers	242
15	LVD Lines Rehabilitation	FA - IRONWOOD RD, ROSCOMMON - DSRV	37	1	Project	Imminent Rehabilitation	GERRISH	Deteriorated Service Replacement ; Customers	1
16	LVD Lines Rehabilitation	FA - N BLISS RD, SUMNER - SVLT	27	1	Project	Imminent Rehabilitation	SEVILLE	Improve Secondary Voltage ; Customers	5
17	LVD Lines Rehabilitation	FA - E LUDINGTON, CLARE- OHL - PFCP	42	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Underground Primary ; Customers	43
18	LVD Lines Rehabilitation	FA - E LUDINGTON, CLARE- UGL - PFCP	46	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Underground Primary ; Customers	43
19	LVD Lines Rehabilitation	FA - E LUDINGTON, CLARE- UGS	4	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Underground Primary ; Customers	43
20	LVD Lines Rehabilitation	FA - E LUDINGTON, CLARE-UGS--DE	4	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Underground Primary ; Customers	43
21	LVD Lines Rehabilitation	FA - AMHERST AVE KZOO	9	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	242
22	LVD Lines Rehabilitation	FA - CRANE AVE, KZO - ESIC OHL	48	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
23	LVD Lines Rehabilitation	FA - MERSHON ST, SAG; SVLT	55	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
24	LVD Lines Rehabilitation	FA - S WISE RD, MT P - SVLT	15	1	Project	Imminent Rehabilitation	UNION	Improve Secondary Voltage ; Customers	5
25	LVD Lines Rehabilitation	FA - FINDLEY RD, STRG - BAD URD	68	1	Project	Imminent Rehabilitation	CENTREVILLE	Replace Deteriorated Underground Primary ; Customers	43
26	LVD Lines Rehabilitation	FA - NATIONAL AVE NW, GR - SVLT	96	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
27	LVD Lines Rehabilitation	FA - W MAIN ST, KALAMAZOO	35	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
28	LVD Lines Rehabilitation	FA - ROLLING RIDGE LN NW GR - OHC	3	1	Project	Imminent Rehabilitation	WALKER	Correct Conductor Clearance Violation ; Customers	24
29	LVD Lines Rehabilitation	FA - WINESAP DR NE, GR - PMBC	10	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Padmount to Building Clearance Violation ; Customers	1
30	LVD Lines Rehabilitation	FA - S GLEANER RD,SGN;HPMT;ESIC UGL	3	1	Project	Imminent Rehabilitation	FREMONT	Repair Hole in Padmount Enclosure ; Customers	1
31	LVD Lines Rehabilitation	FA - FERDON RD, KZOO	16	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
32	LVD Lines Rehabilitation	FA - BIRCHCREST DR - PFCP	100	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
33	LVD Lines Rehabilitation	FA - PARKSIDE BLVD, JACKSON - DSRV	76	1	Project	Imminent Rehabilitation	SUMMIT	Deteriorated Service Replacement ; Customers	1
34	LVD Lines Rehabilitation	FA - Eastland Rd - OHS	0	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
35	LVD Lines Rehabilitation	FA - COOLIDGE RD, MUSKEGON - SVLT	52	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
36	LVD Lines Rehabilitation	FA - HIGHLAND ST, MUSKEGON - SVLT	101	1	Project	Imminent Rehabilitation	MUSKEGON HTS	Improve Secondary Voltage ; Customers	5
37	LVD Lines Rehabilitation	FA - S RUMSEY RD, AU GRES - SVLT	15	1	Project	Imminent Rehabilitation	AU GRES	Improve Secondary Voltage ; Customers	5
38	LVD Lines Rehabilitation	FA - BUTLER ST,RLU - flre	11	1	Project	Imminent Rehabilitation	SAUGATUCK	Correct Padmount to Building Clearance Violation ; Customers	1
39	LVD Lines Rehabilitation	FA - S SHERIDAN RD - SVLT	5	1	Project	Imminent Rehabilitation	STANTON	Improve Secondary Voltage ; Customers	5
40	LVD Lines Rehabilitation	FA - E THOMAS ST, PARCHMENT	22	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	242
41	LVD Lines Rehabilitation	FA - KNOLLWOOD ST NE, RFD - SVLT	26	1	Project	Imminent Rehabilitation	PLAINFIELD	Improve Secondary Voltage ; Customers	5
42	LVD Lines Rehabilitation	FA - LINCOLN RD, HAMILTON - POL	9	1	Project	Imminent Rehabilitation	HEATH	Replace Deteriorated Pole ; Customers	242
43	LVD Lines Rehabilitation	FA - ALVIN DR, SIX LAKES - SVLT	15	1	Project	Imminent Rehabilitation	EDMORE	Improve Secondary Voltage ; Customers	5
44	LVD Lines Rehabilitation	FA - W PERE MARQUETTE RD, COLEMAN	11	1	Project	Imminent Rehabilitation	COLEMAN	Correct Conductor Clearance Violation ; Customers	20
45	LVD Lines Rehabilitation	FA - WOODMERE AVE SE, GR - SVLT	136	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
46	LVD Lines Rehabilitation	FA - MACKINAW ST, SAG; SVLT	21	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
47	LVD Lines Rehabilitation	FA - BINSCARTH ST, SAG; SVLT	1	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
48	LVD Lines Rehabilitation	FA - BINSCARTH, SAG; SVLT	1	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
49	LVD Lines Rehabilitation	FA - N GRANDJEAN RD, ROSE CTY; POL	9	1	Project	Imminent Rehabilitation	ROSE CITY	Replace Deteriorated Pole ; Customers	242
50	LVD Lines Rehabilitation	FA - EGGLESTON RD, MIO; SVLT	16	1	Project	Imminent Rehabilitation	MENTOR	Improve Secondary Voltage ; Customers	5
51	LVD Lines Rehabilitation	FA - ST AVE - FLRE	24	1	Project	Imminent Rehabilitation	WATSON	Replace Deteriorated Pole ; Customers	242
52	LVD Lines Rehabilitation	FA - W MAPLE GROVE RD, FWL; POL	9	1	Project	Imminent Rehabilitation	FARWELL	Replace Deteriorated Pole ; Customers	242
53	LVD Lines Rehabilitation	FA - HOLIDAY DR, GREENVILLE - SVLT	42	1	Project	Imminent Rehabilitation	GREENVILLE	Improve Secondary Voltage ; Customers	5
54	LVD Lines Rehabilitation	FA - NOTTINGHAM TER, MIDL; DSRV	50	1	Project	Imminent Rehabilitation	MIDLAND	Deteriorated Service Replacement ; Customers	1
55	LVD Lines Rehabilitation	FA - FOREST DR LUPTON - POL	9	1	Project	Imminent Rehabilitation	LOGAN	Replace Deteriorated Pole ; Customers	242
56	LVD Lines Rehabilitation	FA - TH ST, PLAINWELL - POL	6	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole ; Customers	242
57	LVD Lines Rehabilitation	FA - TH ST DORR - FRRE	16	1	Project	Imminent Rehabilitation	SALEM	Retire and Remove Unused Assets; Customers	58
58	LVD Lines Rehabilitation	FA - MARTIN RD LUPTON - SVLT	15	1	Project	Imminent Rehabilitation	LOGAN	Improve Secondary Voltage ; Customers	5
59	LVD Lines Rehabilitation	FA - CLINTON ST HOMER	14	1	Project	Imminent Rehabilitation	HOMER	Improve Secondary Voltage ; Customers	5
60	LVD Lines Rehabilitation	FA - SOUTHWOOD DR, HARRISON - SVLT	6	1	Project	Imminent Rehabilitation	HARRISON	Improve Secondary Voltage ; Customers	5
61	LVD Lines Rehabilitation	FA - PEET RD, CHESANING; OHC	15	1	Project	Imminent Rehabilitation	CHESANING	Correct Conductor Clearance Violation ; Customers	24
62	LVD Lines Rehabilitation	FA - RICHARDI ST, BELLAIRE - SVLT	15	1	Project	Imminent Rehabilitation	BELLAIRE	Improve Secondary Voltage ; Customers	5
63	LVD Lines Rehabilitation	FA - S OAK DR, BEAVERTON - OHC	5	1	Project	Imminent Rehabilitation	BUCKEYE	Correct Conductor Clearance Violation ; Customers	24
64	LVD Lines Rehabilitation	FA - BIRCH ST, BRECKENRIDGE; SVLT	61	1	Project	Imminent Rehabilitation	BRECKENRIDGE	Improve Secondary Voltage ; Customers	5
65	LVD Lines Rehabilitation	FA - WILLIAMS ST, HOWARD CITY - SVLT	15	1	Project	Imminent Rehabilitation	HOWARD CITY	Improve Secondary Voltage ; Customers	5
66		**LVD Lines Rehabilitation Subtotal**	**1,834**						

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Page: 16 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	E LAKEVIEW HILLS RD TC-ck w lvdp*	11	1	Project	Imminent Rehabilitation	TRAVERSE CITY	Replace Deteriorated Pole ; Customers	242
2	LVD Lines Rehabilitation	MILE RD NE, GR - UPGRADE	10	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Service Replacement ; Customers	1
3	LVD Lines Rehabilitation	W MICHIGAN AVE BCK-ESIC STL	1	1	Project	Imminent Rehabilitation	SPRINGFIELD	Repair Damaged Streetlight ; Customers	-
4	LVD Lines Rehabilitation	prospect ave se, grand rapids	20	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
5	LVD Lines Rehabilitation	th ST SE GRAND RAPIDS%	18	1	Project	Imminent Rehabilitation	KENTWOOD	Correct Conductor Clearance Violation ; Customers	24
6	LVD Lines Rehabilitation	SUNSHINE MUSKEGON FAILED PH UGL	68	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Underground Primary ; Customers	43
7	LVD Lines Rehabilitation	BEECHTREE RD, GLEN ARBOR	15	1	Project	Imminent Rehabilitation	EMPIRE	Correct Conductor Clearance Violation ; Customers	24
8	LVD Lines Rehabilitation	TH ST SE	5	1	Project	Imminent Rehabilitation	CALEDONIA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
9	LVD Lines Rehabilitation	Old th St SE Mister Car Wash UGL	30	1	Project	Imminent Rehabilitation	ADA	Improve Secondary Voltage ; Customers	5
10	LVD Lines Rehabilitation	TH AVE, HUDSONVILLE-clearance	7	1	Project	Imminent Rehabilitation	BLENDON	Attachment Clearance Violation ; Customers	1
11	LVD Lines Rehabilitation	S DUNNS FARM RD	15	1	Project	Imminent Rehabilitation	CLEVELAND	Improve Secondary Voltage ; Customers	5
12	LVD Lines Rehabilitation	CRITICAL FL - PARKDALE AVE - MANISTE	25	1	Project	Imminent Rehabilitation	EASTLAKE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
13	LVD Lines Rehabilitation	CRITICAL FL FLUSHING RD FLINT	50	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
14	LVD Lines Rehabilitation	CRITICAL FL FRUITPORT JUDSON RD LCP Y	13	1	Project	Imminent Rehabilitation	FRUITPORT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
15	LVD Lines Rehabilitation	CRITICAL FL GLEN LK HOMESTEAD LCP OLH	44	1	Project	Imminent Rehabilitation	CLEVELAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
16	LVD Lines Rehabilitation	CRITICAL FL GLEN LK HOMESTEAD LCP UGL	150	1	Project	Imminent Rehabilitation	CLEVELAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
17	LVD Lines Rehabilitation	Critical FL Saranac Bluewater HWY	20	1	Project	Imminent Rehabilitation	SARANAC	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
18	LVD Lines Rehabilitation	CRITICAL FL-VANDERBILT_CORWITH LCP	115	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
19	LVD Lines Rehabilitation	FA - E KILGORE RD	3	1	Project	Imminent Rehabilitation	KALAMAZOO	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
20	LVD Lines Rehabilitation	FA - FOSTER AVE, BATTLE CREEK - SVLT	26	1	Project	Imminent Rehabilitation	BATTLE CREEK	Improve Secondary Voltage ; Customers	5
21	LVD Lines Rehabilitation	FA - HUBBARD RD, CONCORD - POL	15	1	Project	Imminent Rehabilitation	HANOVER	Replace Deteriorated Pole ; Customers	242
22	LVD Lines Rehabilitation	FA - CENTER ST, PLAINWELL - OHC	6	1	Project	Imminent Rehabilitation	PRAIRIEVILLE	Correct Conductor Clearance Violation ; Customers	24
23	LVD Lines Rehabilitation	FA - CAMELOT DR, SGN; ODCE	40	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
24	LVD Lines Rehabilitation	FA - CHICAGO DR - SLVT	8	1	Project	Imminent Rehabilitation	ZEELAND	Improve Secondary Voltage ; Customers	5
25	LVD Lines Rehabilitation	FA - BELLMAN RD, GRASS LAKE - POL	7	1	Project	Imminent Rehabilitation	GRASS LAKE	Replace Deteriorated Pole ; Customers	242
26	LVD Lines Rehabilitation	FA - W WILLARD, TRUFANT - SVLT	15	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
27	LVD Lines Rehabilitation	FA - HAYES, CARSON CITY - SVLT	7	1	Project	Imminent Rehabilitation	CARSON CITY	Improve Secondary Voltage ; Customers	5
28	LVD Lines Rehabilitation	FA - E Bay St, E TWS; POL	50	1	Project	Imminent Rehabilitation	TAWAS CITY	Replace Deteriorated Pole ; Customers	242
29	LVD Lines Rehabilitation	FA - E Bay St, E TWS; POL SVC RM	1	1	Project	Imminent Rehabilitation	TAWAS CITY	Replace Deteriorated Pole ; Customers	242
30	LVD Lines Rehabilitation	FA - E Bay St, E TWS; POL SVCUnit	8	1	Project	Imminent Rehabilitation	TAWAS CITY	Replace Deteriorated Pole ; Customers	242
31	LVD Lines Rehabilitation	FA - E Bay St, E TWS; POL_UGL	22	1	Project	Imminent Rehabilitation	TAWAS CITY	Replace Deteriorated Pole ; Customers	242
32	LVD Lines Rehabilitation	FA - FRISBIE BLVD	19	1	Project	Imminent Rehabilitation	SPRINGFIELD	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
33	LVD Lines Rehabilitation	FA - BARNEY DR, HOUGHTON LK - SVLT	15	1	Project	Imminent Rehabilitation	DENTON	Improve Secondary Voltage ; Customers	5
34	LVD Lines Rehabilitation	FA - DALLAS AVE SE, GR - SVLT	84	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
35	LVD Lines Rehabilitation	FA - HOGAN RD, GAINES - OHC	15	1	Project	Imminent Rehabilitation	ARGENTINE	Correct Conductor Clearance Violation ; Customers	24
36	LVD Lines Rehabilitation	FA - E POTTER RD, DAVISON - SVLT	6	1	Project	Imminent Rehabilitation	DAVISON	Improve Secondary Voltage ; Customers	5
37	LVD Lines Rehabilitation	FA - N CUT, ROSCOMMON - OHC	10	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	24
38	LVD Lines Rehabilitation	FA - LINCOLN ST, ALLEGAN - POL	9	1	Project	Imminent Rehabilitation	ALLEGAN	Replace Deteriorated Pole ; Customers	242
39	LVD Lines Rehabilitation	FA - NATIONAL AVE NW, GR - ODCE	22	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
40	LVD Lines Rehabilitation	FA - MILE RD MSHL	26	1	Project	Imminent Rehabilitation	MARSHALL	Correct Conductor Clearance Violation ; Customers	24
41	LVD Lines Rehabilitation	FA - N GROW RD, STANTON - OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
42	LVD Lines Rehabilitation	FA - TH AVE SHELBYVILLE - SVLT	2	1	Project	Imminent Rehabilitation	WAYLAND	Improve Secondary Voltage ; Customers	5
43	LVD Lines Rehabilitation	FA - S TH ST, SGN; ODCE	9	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
44	LVD Lines Rehabilitation	FA - N BEYER RD, SGN; OHC	6	1	Project	Imminent Rehabilitation	REESE	Correct Conductor Clearance Violation ; Customers	24
45	LVD Lines Rehabilitation	FA - W ROOSEVELT RD, PER - SVLT	15	1	Project	Imminent Rehabilitation	MAPLE RAPIDS	Improve Secondary Voltage ; Customers	5
46	LVD Lines Rehabilitation	FA - E UNION CITY RD RM OSPREY NEST	19	1	Project	Imminent Rehabilitation	COLDWATER	Replace Deteriorated Pole Top Equipment ; Customers	206
47	LVD Lines Rehabilitation	FA - SUNSET HILLS AVE NW - OHC	2	1	Project	Imminent Rehabilitation	WALKER	Correct Conductor Clearance Violation ; Customers	24
48	LVD Lines Rehabilitation	FA - BANKS LAKE RD, GOWEN-SVLT-OH	8	1	Project	Imminent Rehabilitation	NELSON	Improve Secondary Voltage ; Customers	5
49	LVD Lines Rehabilitation	FA - BANKS LAKE RD, GOWEN-SVLT-UG	51	1	Project	Imminent Rehabilitation	NELSON	Improve Secondary Voltage ; Customers	5
50	LVD Lines Rehabilitation	FA - REDMOND AVE - SVLT	5	1	Project	Imminent Rehabilitation	NELSON	Improve Secondary Voltage ; Customers	5
51	LVD Lines Rehabilitation	FA - EMILY ST, SGN; BOVE-OHS	1	1	Project	Imminent Rehabilitation	SAGINAW	Relocate Electric With Structure Encroachment ; Customers	1
52	LVD Lines Rehabilitation	FA HICKORY RD FRUITPORT SVLT	15	1	Project	Imminent Rehabilitation	FRUITPORT	Improve Secondary Voltage ; Customers	5
53	LVD Lines Rehabilitation	FA - TH AVE NW, GR - OHC	7	1	Project	Imminent Rehabilitation	ALPINE	Correct Conductor Clearance Violation ; Customers	20
54	LVD Lines Rehabilitation	FA - CARLOS AVE, ROSCOMMON; OHC	5	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	24
55	LVD Lines Rehabilitation	FA - N ROSE ST, KALAMAZOO - POL	6	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	242
56	LVD Lines Rehabilitation	FA - MAINE ST SGN; SVLT	13	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
57	LVD Lines Rehabilitation	FA - PONTIAC RD SE, GR - OH SVC	1	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
58	LVD Lines Rehabilitation	FA - PONTIAC RD SE, GR - SVLT	59	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
59	LVD Lines Rehabilitation	FA - MURPHY LN	13	1	Project	Imminent Rehabilitation	GENEVA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
60	LVD Lines Rehabilitation	FA - E OP AVE CLIMAX	13	1	Project	Imminent Rehabilitation	CLIMAX	Retire and Remove Unused Assets; Customers	58
61	LVD Lines Rehabilitation	FA - PRINCE LN, MUSKEGON - UGL	11	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
62	LVD Lines Rehabilitation	FA - PRINCE LN, MUSKEGON - VLT CHRT	9	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
63	LVD Lines Rehabilitation	FA - KENOWA SW, GR - SVLT	41	1	Project	Imminent Rehabilitation	WALKER	Improve Secondary Voltage ; Customers	5
64	LVD Lines Rehabilitation	FA - SPRING ARBOR RD, JAX - SVLT	0	1	Project	Imminent Rehabilitation	JACKSON	Improve Secondary Voltage ; Customers	5
65	LVD Lines Rehabilitation	FA - E GENESEE, SGN; BOVE-OHS	1	1	Project	Imminent Rehabilitation	SAGINAW	Relocate Electric With Structure Encroachment ; Customers	1
66		**LVD Lines Rehabilitation Subtotal**	**1,358**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 17 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA - HILLSIDE CT, REED CITY - SVLT	0	1	Project	Imminent Rehabilitation	REED CITY	Improve Secondary Voltage ; Customers	5
2	LVD Lines Rehabilitation	FA - N ALGER RD, ALMA; POL	4	1	Project	Imminent Rehabilitation	ALMA	Replace Deteriorated Pole ; Customers	242
3	LVD Lines Rehabilitation	FA - TH ST	9	1	Project	Imminent Rehabilitation	OSHTEMO	Deteriorated Service Replacement ; Customers	1
4	LVD Lines Rehabilitation	FA - S LINCOLN RD MT PLEASANT - DSRV	9	1	Project	Imminent Rehabilitation	MT PLEASANT	Deteriorated Service Replacement ; Customers	1
5	LVD Lines Rehabilitation	FA - CROSS LN, HAMILTON - PVLT	282	1	Project	Imminent Rehabilitation	HEATH	Improve Primary Voltage ; Customers	520
6	LVD Lines Rehabilitation	FA - TH ST, ALLEGAN - OHC	8	1	Project	Imminent Rehabilitation	CHESHIRE	Correct Conductor Clearance Violation ; Customers	20
7	LVD Lines Rehabilitation	FA - TH AVE, HOLLAND - OHC	8	1	Project	Imminent Rehabilitation	HOLLAND	Correct Conductor Clearance Violation ; Customers	20
8	LVD Lines Rehabilitation	FA - S THIRTEENTH ST, SGN; ODCE	9	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
9	LVD Lines Rehabilitation	FA - N Mile, Pinconning - PVLT	7	1	Project	Imminent Rehabilitation	LINCOLN	Improve Primary Voltage ; Customers	520
10	LVD Lines Rehabilitation	FA- BELSAY RD, GRAND BLANC - POL	13	1	Project	Imminent Rehabilitation	BURTON	Replace Deteriorated Pole ; Customers	242
11	LVD Lines Rehabilitation	FA - N US HIGHWAY BKRV - OHC	7	1	Project	Imminent Rehabilitation	CALEDONIA	Correct Conductor Clearance Violation ; Customers	24
12	LVD Lines Rehabilitation	FA - MILE RD NW COMSTOCK PK - DSRV	42	1	Project	Imminent Rehabilitation	WALKER	Deteriorated Service Replacement ; Customers	1
13	LVD Lines Rehabilitation	FA - W BRIDGE ST, PLAINWELL - DSRV	48	1	Project	Imminent Rehabilitation	PLAINWELL	Deteriorated Service Replacement ; Customers	1
14	LVD Lines Rehabilitation	FA - MARYLAND AVE NE, GR - PMBC	16	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Padmount to Building Clearance Violation ; Customers	1
15	LVD Lines Rehabilitation	FA - MARY CT, SAG; SVLT ESIC OHL	9	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
16	LVD Lines Rehabilitation	FA - TH AVE - SVLT	19	1	Project	Imminent Rehabilitation	CLYDE	Improve Secondary Voltage ; Customers	5
17	LVD Lines Rehabilitation	FA - RIVER RD	32	1	Project	Imminent Rehabilitation	COLDWATER	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
18	LVD Lines Rehabilitation	FA - TH AVE, FENNVILLE - DSRV	26	1	Project	Imminent Rehabilitation	CLYDE	Deteriorated Service Replacement ; Customers	1
19	LVD Lines Rehabilitation	FA - BUCHANAN SW, WYOMING - OHC	10	1	Project	Imminent Rehabilitation	KENTWOOD	Correct Conductor Clearance Violation ; Customers	24
20	LVD Lines Rehabilitation	FA - E DYER RD, PRESCOTT - RREG	3	1	Project	Imminent Rehabilitation	PRESCOTT	Replace Deteriorated Regulator ; Customers	155
21	LVD Lines Rehabilitation	FA - DUNWOODY CT, KZOO	22	1	Project	Imminent Rehabilitation	PORTAGE	Improve Secondary Voltage ; Customers	5
22	LVD Lines Rehabilitation	FA - M - SVLT	16	1	Project	Imminent Rehabilitation	CADILLAC	Improve Secondary Voltage ; Customers	5
23	LVD Lines Rehabilitation	FA - CURTIS RD, HALE - SVLT	15	1	Project	Imminent Rehabilitation	PLAINFIELD	Improve Secondary Voltage ; Customers	5
24	LVD Lines Rehabilitation	FA - E SUPERIOR ST, ALMA; ODCE	9	1	Project	Imminent Rehabilitation	ALMA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
25	LVD Lines Rehabilitation	FA - BYRON RD, ZEELAND - POL	5	1	Project	Imminent Rehabilitation	ZEELAND	Replace Deteriorated Pole ; Customers	242
26	LVD Lines Rehabilitation	FA - PARTRIDGE ST, FLINT-SVLT	82	1	Project	Imminent Rehabilitation	FLINT	Improve Secondary Voltage ; Customers	5
27	LVD Lines Rehabilitation	FA - RITTER RD, SAGINAW; SVLT	33	1	Project	Imminent Rehabilitation	REESE	Improve Secondary Voltage ; Customers	5
28	LVD Lines Rehabilitation	FA - RITTER RD, SAGINAW; SVLT UPO	2	1	Project	Imminent Rehabilitation	REESE	Improve Secondary Voltage ; Customers	5
29	LVD Lines Rehabilitation	FA - W Q AVE., KALAMAZOO	6	1	Project	Imminent Rehabilitation	TEXAS	Replace Deteriorated Pole ; Customers	242
30	LVD Lines Rehabilitation	FA - Norton Center Dr, MUS - PFCP	57	1	Project	Imminent Rehabilitation	NORTON SHORES	Replace Deteriorated Underground Primary ; Customers	43
31	LVD Lines Rehabilitation	FA - Clayton Ave NW, GR - SVLT	13	1	Project	Imminent Rehabilitation	WALKER	Improve Secondary Voltage ; Customers	5
32	LVD Lines Rehabilitation	FA - TIMBER CREST, ROCKFORD - PMBC	4	1	Project	Imminent Rehabilitation	PLAINFIELD	Correct Padmount to Building Clearance Violation ; Customers	1
33	LVD Lines Rehabilitation	FA - JANES RD, SGN; DSRV ESIC OHS	2	1	Project	Imminent Rehabilitation	REESE	Deteriorated Service Replacement ; Customers	1
34	LVD Lines Rehabilitation	FA - JANES RD, SGN; ODCE ESIC OHL	6	1	Project	Imminent Rehabilitation	REESE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
35	LVD Lines Rehabilitation	FA - SIPPERLEY TRL, GVL - PFCP OHL	9	1	Project	Imminent Rehabilitation	GREENVILLE	Replace Deteriorated Underground Primary ; Customers	43
36	LVD Lines Rehabilitation	FA - SIPPERLEY TRL, GVL - PFCP UGL	67	1	Project	Imminent Rehabilitation	GREENVILLE	Replace Deteriorated Underground Primary ; Customers	43
37	LVD Lines Rehabilitation	FA - TH AVE HUDSONVILLE - POL	5	1	Project	Imminent Rehabilitation	BYRON	Replace Deteriorated Pole ; Customers	242
38	LVD Lines Rehabilitation	FA - RAEWAHN RD, SGN; POL	6	1	Project	Imminent Rehabilitation	KOCHVILLE	Replace Deteriorated Pole ; Customers	242
39	LVD Lines Rehabilitation	FA - EVAFNSTON AVE, MUSKEGON - PVLT	6	1	Project	Imminent Rehabilitation	EGELSTON	Improve Primary Voltage ; Customers	520
40	LVD Lines Rehabilitation	FA - M, KINGSLEY - SVLT	15	1	Project	Imminent Rehabilitation	BUCKLEY	Improve Secondary Voltage ; Customers	5
41	LVD Lines Rehabilitation	FA - MICHIGAN ST, ELWELL; ODCE	9	1	Project	Imminent Rehabilitation	SEVILLE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
42	LVD Lines Rehabilitation	FA - LOOMIS ST, JACKSON - SVLT	33	1	Project	Imminent Rehabilitation	JACKSON	Improve Secondary Voltage ; Customers	5
43	LVD Lines Rehabilitation	FA - S COOLIDGE DR, SIX LAKES; POL	53	1	Project	Imminent Rehabilitation	EDMORE	Replace Deteriorated Pole ; Customers	242
44	LVD Lines Rehabilitation	FA - MILE,MECOSTA - SVLT	15	1	Project	Imminent Rehabilitation	MECOSTA	Improve Secondary Voltage ; Customers	5
45	LVD Lines Rehabilitation	FA - E HOLLAND RD, SGN; ESIC OHS	1	1	Project	Imminent Rehabilitation	REESE	Deteriorated Service Replacement ; Customers	1
46	LVD Lines Rehabilitation	FA - E HOLLAND RD, SGN; ESIC OHL	10	1	Project	Imminent Rehabilitation	REESE	Correct Conductor Clearance Violation ; Customers	24
47	LVD Lines Rehabilitation	FA - JANES RD, SGN; SVLT	27	1	Project	Imminent Rehabilitation	REESE	Improve Secondary Voltage ; Customers	5
48	LVD Lines Rehabilitation	FA - SUPERIOR AVE - ODCE	15	1	Project	Imminent Rehabilitation	GAYLORD	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
49	LVD Lines Rehabilitation	FA - S DUNNS FARM RD MAPLE CTY	11	1	Project	Imminent Rehabilitation	CLEVELAND	Replace Deteriorated Pole ; Customers	242
50	LVD Lines Rehabilitation	FA - CEDAR RD, VANDERBILT-ESIC OHL	5	1	Project	Imminent Rehabilitation	VANDERBILT	Correct Conductor Clearance Violation ; Customers	20
51	LVD Lines Rehabilitation	FA - CEDAR RD, VANDERBILT-ESIC OHS	2	1	Project	Imminent Rehabilitation	VANDERBILT	Correct Conductor Clearance Violation ; Customers	20
52	LVD Lines Rehabilitation	FA - OTTAWA AVE NW - POL	5	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
53	LVD Lines Rehabilitation	FA - N TH ST KALAMAZOO-guying	13	1	Project	Imminent Rehabilitation	OSHTEMO	Replace Deteriorated Pole ; Customers	242
54	LVD Lines Rehabilitation	FA - GARFIELD RD, FREELAND; PFCP	27	1	Project	Imminent Rehabilitation	TITTABAWASSEE	Replace Deteriorated Underground Primary ; Customers	43
55	LVD Lines Rehabilitation	FA - KOKO LN, JACKSON - OHC	13	1	Project	Imminent Rehabilitation	GRASS LAKE	Correct Conductor Clearance Violation ; Customers	24
56	LVD Lines Rehabilitation	FA - CARLISLE HWY - FLRE	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
57	LVD Lines Rehabilitation	FA - ELM ST - FRE - SVLT	18	1	Project	Imminent Rehabilitation	FREMONT	Improve Secondary Voltage ; Customers	5
58	LVD Lines Rehabilitation	FA - N PINE ST, HEMLOCK - SVLT	22	1	Project	Imminent Rehabilitation	JONESFIELD	Improve Secondary Voltage ; Customers	5
59	LVD Lines Rehabilitation	FA - W MADISON ST, HST	13	1	Project	Imminent Rehabilitation	HASTINGS	Retire and Remove Unused Assets; Customers	58
60	LVD Lines Rehabilitation	FA - IRISH RD, GRAND BLANC - FLRE	26	1	Project	Imminent Rehabilitation	GOODRICH	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
61	LVD Lines Rehabilitation	FA - PORT SHELDON ST ZEELAND-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
62	LVD Lines Rehabilitation	FA - E SCHOOL SEC LK DR, MEC - OHL	3	1	Project	Imminent Rehabilitation	COLFAX	Correct Conductor Clearance Violation ; Customers	24
63	LVD Lines Rehabilitation	FA - E SCHOOL SEC LK DR, MEC - OHS	1	1	Project	Imminent Rehabilitation	COLFAX	Correct Conductor Clearance Violation ; Customers	24
64	LVD Lines Rehabilitation	FA - TIMBERLYNN TRL, SANFORD; BOVE	6	1	Project	Imminent Rehabilitation	TOBACCO	Relocate Electric With Structure Encroachment ; Customers	1
65	LVD Lines Rehabilitation	FA - AC FROM JANES RD, SGN; OHC	1	1	Project	Imminent Rehabilitation	REESE	Correct Conductor Clearance Violation ; Customers	24
66		**LVD Lines Rehabilitation Subtotal**	**1,302**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 18 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA - BEECHNUT-WAVERLY LCP PFCP	264	1	Project	Imminent Rehabilitation	HOLLAND	Replace Deteriorated Underground Primary ; Customers	43
2	LVD Lines Rehabilitation	FA - BELL ROAD/ALBEE TOWNLINE, OHC	17	1	Project	Imminent Rehabilitation	ALBEE	Correct Conductor Clearance Violation ; Customers	24
3	LVD Lines Rehabilitation	FA CASS RD CASS RD LCP FAIL UG	60	1	Project	Imminent Rehabilitation	TRAVERSE CITY	Replace Deteriorated Underground Primary ; Customers	43
4	LVD Lines Rehabilitation	FA - CHAUNCEY-AUSTIN LCP - HPMT	19	1	Project	Imminent Rehabilitation	ALBION	Repair Hole in Padmount Enclosure ; Customers	1
5	LVD Lines Rehabilitation	FA - HAYES ST_HAYES ST LCP FLRE	5	1	Project	Imminent Rehabilitation	GRAND HAVEN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
6	LVD Lines Rehabilitation	FA - HOLTON/MAPLE ISLAND LCP - RREG	22	1	Project	Imminent Rehabilitation	FREMONT	Replace Deteriorated Regulator ; Customers	155
7	LVD Lines Rehabilitation	FA - MACKINAW CITY_POND STREET LCP	5	1	Project	Imminent Rehabilitation	MACKINAW CITY	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
8	LVD Lines Rehabilitation	FA - PIGEON LAKE-PIGEON LCP PFCP	32	1	Project	Imminent Rehabilitation	PARK	Replace Deteriorated Underground Primary ; Customers	43
9	LVD Lines Rehabilitation	FA REHAB BRETON-PLYMOUTH LCP	43	1	Project	Imminent Rehabilitation	E GD RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
10	LVD Lines Rehabilitation	FA - ROSEWOOD-COTTONWOOD LCP	50	1	Project	Imminent Rehabilitation	GEORGETOWN	Improve Secondary Voltage ; Customers	5
11	LVD Lines Rehabilitation	FA - SUGAR RIVER RD, GLADWIN - PFCP	10	1	Project	Imminent Rehabilitation	SAGE	Replace Deteriorated Underground Primary ; Customers	43
12	LVD Lines Rehabilitation	FA - WALDO_LABORATORY LCP - PFCP	38	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Underground Primary ; Customers	43
13	LVD Lines Rehabilitation	FA - WILMOTT_WILMOTT LCP - SCDY	111	1	Project	Imminent Rehabilitation	OTSEGO	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
14	LVD Lines Rehabilitation	FA W WALNUT ST FREMONT SVLT	55	1	Project	Imminent Rehabilitation	FREMONT	Improve Secondary Voltage ; Customers	5
15	LVD Lines Rehabilitation	FA COLRAIN ST SW	65	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
16	LVD Lines Rehabilitation	FA recreation ave evart pri meter	2	1	Project	Imminent Rehabilitation	EVART	Replace Deteriorated Pole ; Customers	242
17	LVD Lines Rehabilitation	FA Hutchinson St Big Rapids	45	1	Project	Imminent Rehabilitation	BIG RAPIDS	Retire and Remove Unused Assets; Customers	58
18	LVD Lines Rehabilitation	FA Hutchinson St Big Rapids SVC	10	1	Project	Imminent Rehabilitation	BIG RAPIDS	Retire and Remove Unused Assets; Customers	58
19	LVD Lines Rehabilitation	FA N REED RD MORLEY	1	1	Project	Imminent Rehabilitation	MORLEY	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
20	LVD Lines Rehabilitation	FA- PAW PAW DR, HOLLAND-OHC	7	1	Project	Imminent Rehabilitation	ZEELAND	Correct Conductor Clearance Violation ; Customers	24
21	LVD Lines Rehabilitation	FA- E DAVID HWY, PEWAMO - POL	91	1	Project	Imminent Rehabilitation	WESTPHALIA	Replace Deteriorated Pole ; Customers	242
22	LVD Lines Rehabilitation	FA W MAIN ST GAYLORD	6	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole ; Customers	242
23	LVD Lines Rehabilitation	FA EASTERN AVE SE GRAND RAPIDS SERV	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Service Replacement ; Customers	1
24	LVD Lines Rehabilitation	FA ARLINGTON ST NE, GRAND RAPIDS	100	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Conductor Clearance Violation ; Customers	20
25	LVD Lines Rehabilitation	FA N MEARS AVE WHITEHALL	12	1	Project	Imminent Rehabilitation	MONTAGUE	Relocate Electric With Structure Encroachment ; Customers	1
26	LVD Lines Rehabilitation	FA TH AVE ALLENDALE	9	1	Project	Imminent Rehabilitation	POLKTON	Retire and Remove Unused Assets; Customers	58
27	LVD Lines Rehabilitation	FA - GRATIOT RD, SGN; LCP ; POL	39	1	Project	Imminent Rehabilitation	FREMONT	Replace Deteriorated Pole ; Customers	242
28	LVD Lines Rehabilitation	FA- ELY ST, ALLEGAN-ODCE	19	1	Project	Imminent Rehabilitation	ALLEGAN	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
29	LVD Lines Rehabilitation	FA INDIAN PT RD BRUTUS SVLT	15	1	Project	Imminent Rehabilitation	PELLSTON	Improve Secondary Voltage ; Customers	5
30	LVD Lines Rehabilitation	FA th ave and mile rd replace pole	18	1	Project	Imminent Rehabilitation	COLFAX	Replace Deteriorated Pole ; Customers	242
31	LVD Lines Rehabilitation	FA NATIONAL AVE SW GRAND RAPIDS	5	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
32	LVD Lines Rehabilitation	FA OJ MORSE DR PCFP - UGL	39	1	Project	Imminent Rehabilitation	HESPERIA	Repair Damaged Streetlight ; Customers	0
33	LVD Lines Rehabilitation	FA BEAVER RD ST CHARLES	3	1	Project	Imminent Rehabilitation	ST CHARLES	Improve Secondary Voltage ; Customers	5
34	LVD Lines Rehabilitation	FA LIME LAKE DR, Sparta - ESIC OHL	0	1	Project	Imminent Rehabilitation	ALGOMA	Improve Secondary Voltage ; Customers	5
35	LVD Lines Rehabilitation	FA SUGARLOAF CLEAR LAKE WATERLOO	26	1	Project	Imminent Rehabilitation	WATERLOO	Replace Deteriorated Pole ; Customers	242
36	LVD Lines Rehabilitation	FA TURNER AVE NW, GR	72	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
37	LVD Lines Rehabilitation	FA S SHORE W FRANKFORT	29	1	Project	Imminent Rehabilitation	FRANKFORT	Improve Secondary Voltage ; Customers	5
38	LVD Lines Rehabilitation	FA ROBERTS ST MUSKEGON	70	1	Project	Imminent Rehabilitation	MUSKEGON	Deteriorated Service Replacement ; Customers	1
39	LVD Lines Rehabilitation	FA MARSHALL RD BOYNE CITY OHC	7	1	Project	Imminent Rehabilitation	BOYNE CITY	Correct Conductor Clearance Violation ; Customers	24
40	LVD Lines Rehabilitation	FA COMO DR GREENVILLE	10	1	Project	Imminent Rehabilitation	GREENVILLE	Improve Secondary Voltage ; Customers	5
41	LVD Lines Rehabilitation	FA N US N STE D SVLT	16	1	Project	Imminent Rehabilitation	ACME	Improve Secondary Voltage ; Customers	5
42	LVD Lines Rehabilitation	FA FRANCIS AVE SE, GR - SPLIT LOAD	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
43	LVD Lines Rehabilitation	FA ACACIA DR NW GRAND RAPIDS	27	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
44	LVD Lines Rehabilitation	FA TH ST ARCADIA DRSV	39	1	Project	Imminent Rehabilitation	ONEKAMA	Deteriorated Service Replacement ; Customers	1
45	LVD Lines Rehabilitation	FA UNION AVE SE	26	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Conductor Clearance Violation ; Customers	20
46	LVD Lines Rehabilitation	FA LAKEVIEW ST - XFMR UPGRADE	23	1	Project	Imminent Rehabilitation	EVERGREEN	Improve Secondary Voltage ; Customers	5
47	LVD Lines Rehabilitation	FA MILL ST LESLIE	7	1	Project	Imminent Rehabilitation	LESLIE	Improve Primary Voltage ; Customers	520
48	LVD Lines Rehabilitation	FA W GRAND RIVER RD, OKEMOS - FLRE	3	1	Project	Imminent Rehabilitation	MERIDIAN	Improve Primary Voltage ; Customers	520
49	LVD Lines Rehabilitation	FA TH ST SW BYRON CENTER	7	1	Project	Imminent Rehabilitation	BYRON	Replace Deteriorated Pole ; Customers	242
50	LVD Lines Rehabilitation	FA N HURON AVE MACKINAW CITY	7	1	Project	Imminent Rehabilitation	MACKINAW CITY	Replace Deteriorated Pole ; Customers	242
51	LVD Lines Rehabilitation	FA DICKINSON ST SW GRAND RAPIDS	46	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
52	LVD Lines Rehabilitation	FA OAKWOOD DR SE, GR - ADD TRF	91	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
53	LVD Lines Rehabilitation	FA FEATHERSTONE RD STURGIS - OHC	5	1	Project	Imminent Rehabilitation	CENTREVILLE	Correct Conductor Clearance Violation ; Customers	24
54	LVD Lines Rehabilitation	FA ENGLEWOOD DR SE	2	1	Project	Imminent Rehabilitation	E GD RAPIDS	Replace Deteriorated Pole ; Customers	242
55	LVD Lines Rehabilitation	FA SWENSBERG AVE NE, GR - WIRE A	11	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Service Replacement ; Customers	1
56	LVD Lines Rehabilitation	FA W LONG LAKE RD ORLEANS	43	1	Project	Imminent Rehabilitation	RONALD	Improve Secondary Voltage ; Customers	5
57	LVD Lines Rehabilitation	FA W CHERRY ST CEDAR SPRINGS	72	1	Project	Imminent Rehabilitation	CEDAR SPRINGS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
58	LVD Lines Rehabilitation	FA HONEYWOOD DR SW GRANDVILLE	1	1	Project	Imminent Rehabilitation	GRANDVILLE	Repair Hole in Padmount Enclosure ; Customers	1
59	LVD Lines Rehabilitation	FA- OLD ALLEGAN RD, FENNVILLE -FRRE	20	1	Project	Imminent Rehabilitation	SAUGATUCK	Retire and Remove Unused Assets; Customers	58
60	LVD Lines Rehabilitation	FA Schuring Rd	16	1	Project	Imminent Rehabilitation	PORTAGE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
61	LVD Lines Rehabilitation	FA - ND ST, SAUGATUCK - SVLT***	14	1	Project	Imminent Rehabilitation	SAUGATUCK	Improve Secondary Voltage ; Customers	5
62	LVD Lines Rehabilitation	FA CALVIN CT SW	18	1	Project	Imminent Rehabilitation	GRANDVILLE	Repair Hole in Padmount Enclosure ; Customers	1
63	LVD Lines Rehabilitation	FA BRANDYWYNE DR NW-POLE	5	1	Project	Imminent Rehabilitation	PLAINFIELD	Replace Deteriorated Pole ; Customers	242
64	LVD Lines Rehabilitation	FA - S Tuscola Rd_BYC; OHC	38	1	Project	Imminent Rehabilitation	BAY CITY	Correct Conductor Clearance Violation ; Customers	24
65	LVD Lines Rehabilitation	FA JOHNSON COURT	0	1	Project	Imminent Rehabilitation	GRANDVILLE	Repair Hole in Padmount Enclosure ; Customers	1
66		**LVD Lines Rehabilitation Subtotal**	**1,972**						

MICHIGAN PUBLIC SERVICE COMMISSION
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Bridge Period LVD Project List
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($000)

Case No.: U-21870
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA UNION AVE SE, WYOMING	1	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
2	LVD Lines Rehabilitation	FA CUSTER RD, BURR OAK	5	1	Project	Imminent Rehabilitation	COLON	Correct Conductor Clearance Violation ; Customers	24
3	LVD Lines Rehabilitation	FA S MOORLAND RD RAVENNA FLRE	20	1	Project	Imminent Rehabilitation	RAVENNA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
4	LVD Lines Rehabilitation	FA N MANITOU TRL OHL REHAB	35	1	Project	Imminent Rehabilitation	LELAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
5	LVD Lines Rehabilitation	FA N MANITOU TRL UGL REHAB	39	1	Project	Imminent Rehabilitation	LELAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
6	LVD Lines Rehabilitation	FA WENONAH AVE INDIAN RIVER	27	1	Project	Imminent Rehabilitation	TUSCARORA	Improve Secondary Voltage ; Customers	5
7	LVD Lines Rehabilitation	FA LAKE HARBOR RD, MUSK - SVLT	9	1	Project	Imminent Rehabilitation	NORTON SHORES	Improve Secondary Voltage ; Customers	5
8	LVD Lines Rehabilitation	FA Graham ST SW	7	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
9	LVD Lines Rehabilitation	FA- HEIGHTS RAVENNA RD, FRTPT -SVLT	40	1	Project	Imminent Rehabilitation	FRUITPORT	Improve Secondary Voltage ; Customers	5
10	LVD Lines Rehabilitation	FA ISLAND LAKE RD KALKASKA	910	1	Project	Imminent Rehabilitation	KALKASKA	Replace Deteriorated Underground Primary ; Customers	43
11	LVD Lines Rehabilitation	FA Sarah Ln, CLD-ESIC UGS	4	1	Project	Imminent Rehabilitation	COLDWATER	Replace Deteriorated Pole ; Customers	242
12	LVD Lines Rehabilitation	FA S VILLAGE DR, WILL PFCP	75	1	Project	Imminent Rehabilitation	ACME	Replace Deteriorated Underground Primary ; Customers	43
13	LVD Lines Rehabilitation	FA Cornfield Dr Flicker	4	1	Project	Imminent Rehabilitation	CEDAR SPRINGS	Improve Secondary Voltage ; Customers	5
14	LVD Lines Rehabilitation	FA TH ST SW BYRON CENTER	16	1	Project	Imminent Rehabilitation	BYRON	Improve Secondary Voltage ; Customers	5
15	LVD Lines Rehabilitation	FA Briggs Rd, Quincy	20	1	Project	Imminent Rehabilitation	QUINCY	Correct Padmount to Building Clearance Violation ; Customers	1
16	LVD Lines Rehabilitation	FA Coit Ave NE Pull Pole	2	1	Project	Imminent Rehabilitation	PLAINFIELD	Improve Secondary Voltage ; Customers	5
17	LVD Lines Rehabilitation	FA Coit Ave NE Grand Rapids Voltage	26	1	Project	Imminent Rehabilitation	PLAINFIELD	Improve Secondary Voltage ; Customers	5
18	LVD Lines Rehabilitation	FA- HUTCHINSON RD, RIVERS - SVLT	8	1	Project	Imminent Rehabilitation	MENDON	Improve Secondary Voltage ; Customers	5
19	LVD Lines Rehabilitation	FA TIFFANY AVE NE, ROCKFORD - POL	5	1	Project	Imminent Rehabilitation	ADA	Replace Deteriorated Pole ; Customers	242
20	LVD Lines Rehabilitation	FA NORTH MANITOU TRAIL LELAND	11	1	Project	Imminent Rehabilitation	NORTHPORT	Replace Deteriorated Pole ; Customers	242
21	LVD Lines Rehabilitation	FA HARRAND RD BUCKLEY	11	1	Project	Imminent Rehabilitation	BUCKLEY	Replace Deteriorated Pole ; Customers	242
22	LVD Lines Rehabilitation	FA VAN BUREN ST HUDSONVILLE	6	1	Project	Imminent Rehabilitation	BLENDON	Improve Secondary Voltage ; Customers	5
23	LVD Lines Rehabilitation	FA Anthony Dr., Centreville BAD UG	35	1	Project	Imminent Rehabilitation	CENTREVILLE	Replace Deteriorated Underground Primary ; Customers	43
24	LVD Lines Rehabilitation	FA CAROLINE PL NE	26	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
25	LVD Lines Rehabilitation	FA GARLAND ST SE - volt comp	26	1	Project	Imminent Rehabilitation	KENTWOOD	Improve Secondary Voltage ; Customers	5
26	LVD Lines Rehabilitation	FA CRESCENT ST NE APT B GRAND RAPIDS	1	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
27	LVD Lines Rehabilitation	FA W SEMINARY ST , CHARLOTTE - POL	6	1	Project	Imminent Rehabilitation	CHARLOTTE	Replace Deteriorated Pole ; Customers	242
28	LVD Lines Rehabilitation	FA PENINSULA DR, TC POL	16	1	Project	Imminent Rehabilitation	TRAVERSE CITY	Replace Deteriorated Pole ; Customers	242
29	LVD Lines Rehabilitation	FA WEST ST ALANSON	41	1	Project	Imminent Rehabilitation	ALANSON	Replace Deteriorated Pole ; Customers	242
30	LVD Lines Rehabilitation	FA S HURON ST voltage charts	19	1	Project	Imminent Rehabilitation	CHEBOYGAN	Improve Secondary Voltage ; Customers	5
31	LVD Lines Rehabilitation	FA REYNARD ST SE	6	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
32	LVD Lines Rehabilitation	FA Cambridge Blvd SE low voltage	33	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
33	LVD Lines Rehabilitation	FA WILSON AVE SW BYRON CENTER	13	1	Project	Imminent Rehabilitation	GRANDVILLE	Improve Secondary Voltage ; Customers	5
34	LVD Lines Rehabilitation	FA HUBERT ST NE, GRAND RAPIDS	5	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
35	LVD Lines Rehabilitation	FA CRYSTAL BEACH RD NW RAPID CITY	15	1	Project	Imminent Rehabilitation	MILTON	Improve Secondary Voltage ; Customers	5
36	LVD Lines Rehabilitation	FA MAIN ST JENISON	2	1	Project	Imminent Rehabilitation	GRANDVILLE	Correct Conductor Clearance Violation ; Customers	24
37	LVD Lines Rehabilitation	FA LAKE MICHIGAN DR NW GRAND RAPIDS	9	1	Project	Imminent Rehabilitation	WALKER	Improve Secondary Voltage ; Customers	5
38	LVD Lines Rehabilitation	FA CROSBY ST NW, GR - DEMO	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
39	LVD Lines Rehabilitation	FA BEEBE RD CHEBOYGAN POL	5	1	Project	Imminent Rehabilitation	CHEBOYGAN	Replace Deteriorated Pole ; Customers	242
40	LVD Lines Rehabilitation	FA mayhew wood dr se grand rapids	33	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Service Replacement ; Customers	1
41	LVD Lines Rehabilitation	FA S State St Big Rapids	43	1	Project	Imminent Rehabilitation	BIG RAPIDS	Improve Secondary Voltage ; Customers	5
42	LVD Lines Rehabilitation	FA S State St Big Rapids A	0	1	Project	Imminent Rehabilitation	BIG RAPIDS	Improve Secondary Voltage ; Customers	5
43	LVD Lines Rehabilitation	FA S State St Big Rapids A	1	1	Project	Imminent Rehabilitation	BIG RAPIDS	Improve Secondary Voltage ; Customers	5
44	LVD Lines Rehabilitation	FA S State St Big Rapids , B&C	0	1	Project	Imminent Rehabilitation	BIG RAPIDS	Improve Secondary Voltage ; Customers	5
45	LVD Lines Rehabilitation	FA S State St Big Rapids	0	1	Project	Imminent Rehabilitation	BIG RAPIDS	Improve Secondary Voltage ; Customers	5
46	LVD Lines Rehabilitation	FA PINE CREEK RD SVLT	27	1	Project	Imminent Rehabilitation	EASTLAKE	Improve Secondary Voltage ; Customers	5
47	LVD Lines Rehabilitation	FA BEECHWOOD NE, GR - SPLIT LOAD	81	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
48	LVD Lines Rehabilitation	FA PENINSULA DR	11	1	Project	Imminent Rehabilitation	PENINSULA	Replace Deteriorated Pole ; Customers	242
49	LVD Lines Rehabilitation	FA Ducey Ave STREETLIGHT WIRE	7	1	Project	Imminent Rehabilitation	MUSKEGON	Repair Damaged Streetlight ; Customers	0
50	LVD Lines Rehabilitation	FA ND ST SW - ESIC/OHL	24	1	Project	Imminent Rehabilitation	WYOMING	Replace Deteriorated Pole ; Customers	242
51	LVD Lines Rehabilitation	FA ANTRIM_ELK RAPIDS LCP OHL PCFP	102	1	Project	Imminent Rehabilitation	ELK RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
52	LVD Lines Rehabilitation	FA ANTRIM_ELK RAPIDS LCP UGL PCFP	53	1	Project	Imminent Rehabilitation	ELK RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
53	LVD Lines Rehabilitation	FA BAGLEY_OTSEGO LAKE LCP SUB #	687	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
54	LVD Lines Rehabilitation	FA BAGLEY_OTSEGO LAKE LCP SUB #	243	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
55	LVD Lines Rehabilitation	FA BAILEY HALF MOON LAKE FLRE	51	1	Project	Imminent Rehabilitation	ASHLAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
56	LVD Lines Rehabilitation	FA -BENJAMIN ST AND IRVING ST, SGN; POL	34	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole ; Customers	242
57	LVD Lines Rehabilitation	FA BILLWOOD_BILLWOOD LCP	14	1	Project	Imminent Rehabilitation	LANSING	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
58	LVD Lines Rehabilitation	FA Bowen / Blossom RFI	0	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Radio Frequency Interference ; Customers	1
59	LVD Lines Rehabilitation	FA Bowen_Blossom Pol RFI interference	27	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	242
60	LVD Lines Rehabilitation	FA BRETON-PLYMOUTH LCP UG	57	1	Project	Imminent Rehabilitation	E GD RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
61	LVD Lines Rehabilitation	FA Calvin Beltline LCP	107	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
62	LVD Lines Rehabilitation	FA Calvin Forest Hills LCP	96	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
63	LVD Lines Rehabilitation	FA Cascade Thorncrest I- HWY crossing	25	1	Project	Imminent Rehabilitation	LOWELL	Retire and Remove Unused Assets; Customers	58
64	LVD Lines Rehabilitation	FA- CHICAGO-PINEBROOK LCP	109	1	Project	Imminent Rehabilitation	HUDSONVILLE	Replace Deteriorated Underground Primary ; Customers	43
65	LVD Lines Rehabilitation	FA CMPLT N EVERGREEN DR, BRUN SVLT	5	1	Project	Imminent Rehabilitation	FRANKENMUTH	Improve Secondary Voltage ; Customers	5
66		**LVD Lines Rehabilitation Subtotal**	**3,378**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA DEMO MACDONALD AVE FLINT	3	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Pole ; Customers	242
2	LVD Lines Rehabilitation	FA EDDY/FINDLEY LCP UG Tie	128	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Underground Primary ; Customers	43
3	LVD Lines Rehabilitation	FA FLRE Derby_Derby	79	1	Project	Imminent Rehabilitation	DOUGLASS	Replace Deteriorated Pole ; Customers	242
4	LVD Lines Rehabilitation	FA FOREMAN CKT _ VERGENNES ST SE	11	1	Project	Imminent Rehabilitation	ADA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
5	LVD Lines Rehabilitation	FA FRRE - FULFORD ST, KZOO	5	1	Project	Imminent Rehabilitation	KALAMAZOO	Retire and Remove Unused Assets; Customers	58
6	LVD Lines Rehabilitation	FA FULTON RIPPLING - RIPPLING DR OHL	3	1	Project	Imminent Rehabilitation	ADA	Replace Deteriorated Underground Primary ; Customers	43
7	LVD Lines Rehabilitation	FA FULTON RIPPLING - RIPPLING DR UGL	99	1	Project	Imminent Rehabilitation	ADA	Replace Deteriorated Underground Primary ; Customers	43
8	LVD Lines Rehabilitation	FA GLEN LAKE/HOMESTEAD LCP	7	1	Project	Imminent Rehabilitation	CLEVELAND	Retire and Remove Unused Assets; Customers	58
9	LVD Lines Rehabilitation	FA GLEN LAKE/HOMESTEAD LCP ESIC OHL	11	1	Project	Imminent Rehabilitation	CLEVELAND	Replace Deteriorated Underground Primary ; Customers	43
10	LVD Lines Rehabilitation	FA GLEN LAKE/HOMESTEAD LCP ESIC UGL	298	1	Project	Imminent Rehabilitation	CLEVELAND	Replace Deteriorated Underground Primary ; Customers	43
11	LVD Lines Rehabilitation	FA GLENDALE_HERCULES Mt Olivet Rd	40	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
12	LVD Lines Rehabilitation	FA GRAND LEDGE_ACADEMY LCP	19	1	Project	Imminent Rehabilitation	GRAND LEDGE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
13	LVD Lines Rehabilitation	FA GRAYLING_BEAR LCP - SVLT	125	1	Project	Imminent Rehabilitation	GRAYLING	Improve Secondary Voltage ; Customers	5
14	LVD Lines Rehabilitation	FA GREENSPIRE E OF TOZER RELOC PRI EQUIP	8	1	Project	Imminent Rehabilitation	PORTAGE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
15	LVD Lines Rehabilitation	FA Grenlund Rd reconductorElsieBannister	366	1	Project	Imminent Rehabilitation	ELSIE	Improve Primary Voltage ; Customers	520
16	LVD Lines Rehabilitation	FA Harvey_Diamond Lake Dr SE	65	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
17	LVD Lines Rehabilitation	FA HASTINGS BROADWAY LCP SECTRPL	27	1	Project	Imminent Rehabilitation	HASTINGS	Replace Deteriorated Recloser ; Customers	330
18	LVD Lines Rehabilitation	FA HOTCHKISS_BAY VALLEY LCP - UG	80	1	Project	Imminent Rehabilitation	MONITOR	Replace Deteriorated Underground Primary ; Customers	43
19	LVD Lines Rehabilitation	FA Ivanrest_Ramble Conductor Slap	5	1	Project	Imminent Rehabilitation	GRANDVILLE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
20	LVD Lines Rehabilitation	FA- KRAFT TAHOE LCP GLENWOOD HILLS	168	1	Project	Imminent Rehabilitation	CASCADE	Replace Deteriorated Underground Primary ; Customers	43
21	LVD Lines Rehabilitation	FA- KRAFT TAHOE LCP GLENWOOD OHL	13	1	Project	Imminent Rehabilitation	CASCADE	Replace Deteriorated Underground Primary ; Customers	43
22	LVD Lines Rehabilitation	FA MACKINAW CITY_POND STREET LCP	65	1	Project	Imminent Rehabilitation	MACKINAW CITY	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
23	LVD Lines Rehabilitation	FA MCCRACKEN_MCCRACKEN LCP	19	1	Project	Imminent Rehabilitation	ROOSEVELT PRK	Replace Deteriorated Underground Equipment ; Customers	105
24	LVD Lines Rehabilitation	FA Meadowbrooke Karona LCP ,	31	1	Project	Imminent Rehabilitation	KENTWOOD	Replace Deteriorated Underground Equipment ; Customers	105
25	LVD Lines Rehabilitation	FA MURNER_VAN TYLE MILLBOCKER ESIC UGL	161	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
26	LVD Lines Rehabilitation	FA NORTHPORT LIGHTHOUSE LCP	32	1	Project	Imminent Rehabilitation	NORTHPORT	Replace Deteriorated Pole ; Customers	242
27	LVD Lines Rehabilitation	FA ODCE - MARKET ST, HST	148	1	Project	Imminent Rehabilitation	HASTINGS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
28	LVD Lines Rehabilitation	FA ODCE - W MADISON ST, HST	7	1	Project	Imminent Rehabilitation	HASTINGS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
29	LVD Lines Rehabilitation	FA OHC Neibles Ln, Coldwater	9	1	Project	Imminent Rehabilitation	COLDWATER	Correct Conductor Clearance Violation ; Customers	20
30	LVD Lines Rehabilitation	FA OHC CHERYL ANN DR BURTON RD	5	1	Project	Imminent Rehabilitation	BURTON	Correct Conductor Clearance Violation ; Customers	24
31	LVD Lines Rehabilitation	FA ORIOLE BRYANT ROAD LCP	60	1	Project	Imminent Rehabilitation	LUDINGTON	Replace Deteriorated Underground Primary ; Customers	43
32	LVD Lines Rehabilitation	FA OVLD KESSLING ST DEMO	12	1	Project	Imminent Rehabilitation	BURTON	Improve Secondary Voltage ; Customers	5
33	LVD Lines Rehabilitation	FA PFCP Argyle-Camelot Villas OHL	9	1	Project	Imminent Rehabilitation	FOREST	Replace Deteriorated Underground Primary ; Customers	43
34	LVD Lines Rehabilitation	FA PFCP Argyle-Camelot Villas UGL	151	1	Project	Imminent Rehabilitation	FOREST	Replace Deteriorated Underground Primary ; Customers	43
35	LVD Lines Rehabilitation	FA PFCP COURT/WOODLAWN LCP	70	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Underground Primary ; Customers	43
36	LVD Lines Rehabilitation	FA PFCP COURT/WOODLAWN LCP - OHL	24	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Underground Primary ; Customers	43
37	LVD Lines Rehabilitation	FA Pierson_Pierson Sandlake Line Reloc	269	1	Project	Imminent Rehabilitation	PIERSON	Replace Deteriorated Pole ; Customers	242
38	LVD Lines Rehabilitation	FA PMB MADISON AVE SE	8	1	Project	Imminent Rehabilitation	KENTWOOD	Repair Holes in Padmount Base ; Customers	1
39	LVD Lines Rehabilitation	FA POL - W BOND ST, HST	48	1	Project	Imminent Rehabilitation	HASTINGS	Replace Deteriorated Pole ; Customers	242
40	LVD Lines Rehabilitation	FA POL - W CLINTON ST, HST	63	1	Project	Imminent Rehabilitation	HASTINGS	Replace Deteriorated Pole ; Customers	242
41	LVD Lines Rehabilitation	FA POL S. IRISH RD - ECNC UPU	3	1	Project	Imminent Rehabilitation	DAVISON	Replace Deteriorated Pole ; Customers	242
42	LVD Lines Rehabilitation	FA POL W HOLBROOK AVE, FLT	2	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Pole ; Customers	242
43	LVD Lines Rehabilitation	FA POL KESSLING ST DAVISON	2	1	Project	Imminent Rehabilitation	BURTON	Replace Deteriorated Pole ; Customers	242
44	LVD Lines Rehabilitation	FA POLE RELOCATE- CITY RD, MANCHESTER	3	1	Project	Imminent Rehabilitation	MANCHESTER	Replace Deteriorated Pole ; Customers	242
45	LVD Lines Rehabilitation	FA RANGERLAKE_LUPTON LCP _ECNC_RLO	53	1	Project	Imminent Rehabilitation	LOGAN	Replace Deteriorated Pole Top Equipment ; Customers	206
46	LVD Lines Rehabilitation	FA Rothbury_New Era LCP RREG	17	1	Project	Imminent Rehabilitation	NEW ERA	Replace Deteriorated Regulator ; Customers	155
47	LVD Lines Rehabilitation	FA RP OH SEC CABLE W MAUMEE ADR	22	1	Project	Imminent Rehabilitation	ADRIAN	Improve Secondary Voltage ; Customers	5
48	LVD Lines Rehabilitation	FA SAVIDGE_BOOM ROAD LCP FLRE	4	1	Project	Imminent Rehabilitation	GRAND HAVEN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
49	LVD Lines Rehabilitation	FA SHAFFER KEELER LCP UG	47	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Underground Primary ; Customers	43
50	LVD Lines Rehabilitation	FA SHANTY CREEK_LODGE LCP	130	1	Project	Imminent Rehabilitation	KEARNEY	Replace Deteriorated Underground Primary ; Customers	43
51	LVD Lines Rehabilitation	FA SHANTY CREEK_LODGE SUB	130	1	Project	Imminent Rehabilitation	KEARNEY	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
52	LVD Lines Rehabilitation	FA Stevens_Albany low voltage Graham	16	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
53	LVD Lines Rehabilitation	FA STL - - Ashman Circle, Midland	16	1	Project	Imminent Rehabilitation	MIDLAND	Repair Damaged Streetlight ; Customers	0
54	LVD Lines Rehabilitation	FA STL - MCKINLEY PARK, Flint	6	1	Project	Imminent Rehabilitation	FLINT	Repair Damaged Streetlight ; Customers	0
55	LVD Lines Rehabilitation	FA Stonegate/Brevis LCP - RP UG CBL	32	1	Project	Imminent Rehabilitation	GRANDVILLE	Replace Deteriorated Underground Primary ; Customers	43
56	LVD Lines Rehabilitation	FA SVLT - MAPLE RDG ALBION DEMO	27	1	Project	Imminent Rehabilitation	ALBION	Improve Secondary Voltage ; Customers	5
57	LVD Lines Rehabilitation	FA SVLT CONCORD ST DEMO	6	1	Project	Imminent Rehabilitation	FLINT	Improve Secondary Voltage ; Customers	5
58	LVD Lines Rehabilitation	FA SVLT HOLTON_HOLTON FIR AVE	70	1	Project	Imminent Rehabilitation	HOLTON	Improve Secondary Voltage ; Customers	5
59	LVD Lines Rehabilitation	FA Thornapple Ckt _Fulton St Bike Path	142	1	Project	Imminent Rehabilitation	ADA	Replace Deteriorated Pole ; Customers	242
60	LVD Lines Rehabilitation	FA VOLT ISLAND HWY CHARLOTTE	3	1	Project	Imminent Rehabilitation	CHARLOTTE	Improve Secondary Voltage ; Customers	5
61	LVD Lines Rehabilitation	FA- YORKVILLE_HIGHLAND ISLAND - ODCE	137	1	Project	Imminent Rehabilitation	PRAIRIEVILLE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
62	LVD Lines Rehabilitation	FA_ BACON AVE_POL	3	1	Project	Imminent Rehabilitation	PORTAGE	Replace Deteriorated Pole ; Customers	242
63	LVD Lines Rehabilitation	FA_ LAKEVIEW ST_W BRANCH POL	6	1	Project	Imminent Rehabilitation	ROSE CITY	Replace Deteriorated Pole ; Customers	242
64	LVD Lines Rehabilitation	FA__W_LAKESIDE_DR_WEST_BRANCH_SVLT	6	1	Project	Imminent Rehabilitation	MOFFATT	Improve Secondary Voltage ; Customers	5
65	LVD Lines Rehabilitation	FA_ N REED RD HOWARD CITY_PART OH	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
66		**LVD Lines Rehabilitation Subtotal**	**3,650**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA_ N REED RD HOWARD CITY_PARTOF	54	1	Project	Imminent Rehabilitation	MORLEY	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
2	LVD Lines Rehabilitation	FA_ROSE CITY_KLACKING CREEK LCP REG	6	1	Project	Imminent Rehabilitation	ROSE CITY	Improve Primary Voltage ; Customers	520
3	LVD Lines Rehabilitation	FA- MUSKEGON NW-POL	2	1	Project	Imminent Rehabilitation	DOUGLASS	Replace Deteriorated Pole ; Customers	242
4	LVD Lines Rehabilitation	FA- STACEY WOODS NE,GVL-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
5	LVD Lines Rehabilitation	FA- PROSPECT AVE SE - SVLT	46	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
6	LVD Lines Rehabilitation	FA- W KENT RD, Wheeler -PVLT	32	1	Project	Imminent Rehabilitation	LEE	Improve Primary Voltage ; Customers	520
7	LVD Lines Rehabilitation	FA- ARROWHEAD,W BRANCH-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
8	LVD Lines Rehabilitation	FA- BARLOW ST, TRAVERSE CITY - POL	13	1	Project	Imminent Rehabilitation	GARFIELD	Replace Deteriorated Pole ; Customers	242
9	LVD Lines Rehabilitation	FA Fulton St E, Grand Rapids Pole A	65	1	Project	Imminent Rehabilitation	E GD RAPIDS	Replace Deteriorated Pole ; Customers	242
10	LVD Lines Rehabilitation	FA- SHATTUCK RD, SAGINAW-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
11	LVD Lines Rehabilitation	FA- N CLARE AVE HRS	13	1	Project	Imminent Rehabilitation	HARRISON	Deteriorated Service Replacement ; Customers	1
12	LVD Lines Rehabilitation	FA- N CHAMBERS RD, TWS - OHC	13	1	Project	Imminent Rehabilitation	TAWAS	Correct Conductor Clearance Violation ; Customers	24
13	LVD Lines Rehabilitation	FA- Sprinkle Rd-POL	26	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	242
14	LVD Lines Rehabilitation	FA- CHIPPING NORTON CT, SAGINAW-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
15	LVD Lines Rehabilitation	FA- W STATE ST ST JOHNS-SVLT	45	1	Project	Imminent Rehabilitation	ST JOHNS	Improve Secondary Voltage ; Customers	5
16	LVD Lines Rehabilitation	FA- BRICKYARD, TWIN LAKE-FRRE	19	1	Project	Imminent Rehabilitation	HOLTON	Retire and Remove Unused Assets; Customers	58
17	LVD Lines Rehabilitation	FA- RIVER ST, ELK RAPIDS-SVLT	5	1	Project	Imminent Rehabilitation	ELK RAPIDS	Improve Secondary Voltage ; Customers	5
18	LVD Lines Rehabilitation	FA- WELCH LAKE RD GRASS LAKE-POL	27	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole ; Customers	242
19	LVD Lines Rehabilitation	FA- WELCH LAKE RD GRASS LAKE-OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
20	LVD Lines Rehabilitation	FA- Pine St Owosso SVLT	35	1	Project	Imminent Rehabilitation	OWOSSO	Improve Secondary Voltage ; Customers	5
21	LVD Lines Rehabilitation	FA- BURLINGAME AVE, BYRON CNTR-OHC	15	1	Project	Imminent Rehabilitation	WYOMING	Correct Conductor Clearance Violation ; Customers	24
22	LVD Lines Rehabilitation	FA- ST JOHN TRL_B_GAYLORD- SVLT	16	1	Project	Imminent Rehabilitation	GAYLORD	Improve Secondary Voltage ; Customers	5
23	LVD Lines Rehabilitation	FA- W TRAVERSE MAPLE CITY-SVLT	4	1	Project	Imminent Rehabilitation	CLEVELAND	Improve Secondary Voltage ; Customers	5
24	LVD Lines Rehabilitation	FA- River St	141	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
25	LVD Lines Rehabilitation	FA- River St SVC RP FRANCIS ST	2	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
26	LVD Lines Rehabilitation	FA Lakeside Dr SE - EGR-critical toFL	50	1	Project	Imminent Rehabilitation	E GD RAPIDS	Deteriorated Service Replacement ; Customers	1
27	LVD Lines Rehabilitation	FA- JOHNSON RD, SARANAC-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
28	LVD Lines Rehabilitation	FA- CALVIN SE, GR-OHC	16	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Conductor Clearance Violation ; Customers	24
29	LVD Lines Rehabilitation	FA- MAIN EAST JORDAN-SVLT	26	1	Project	Imminent Rehabilitation	EAST JORDAN	Improve Secondary Voltage ; Customers	5
30	LVD Lines Rehabilitation	FA- W LAKE CITY RD ESIC UGS	3	1	Project	Imminent Rehabilitation	BUTTERFIELD	Repair Hole in Padmount Enclosure ; Customers	1
31	LVD Lines Rehabilitation	FA-Alber - ALber LCP 802-ESIC OHL	7	1	Project	Imminent Rehabilitation	BATTLE CREEK	Replace Deteriorated Underground Primary ; Customers	43
32	LVD Lines Rehabilitation	FA-Alber - ALber LCP 802-ESIC UGL	31	1	Project	Imminent Rehabilitation	BATTLE CREEK	Replace Deteriorated Underground Primary ; Customers	43
33	LVD Lines Rehabilitation	FA-Beaverton Tobacco LCP 452	13	1	Project	Imminent Rehabilitation	BEAVERTON	Replace Deteriorated Regulator ; Customers	155
34	LVD Lines Rehabilitation	FA-Cable Replacement Hill Brady LCP 259	17	1	Project	Imminent Rehabilitation	BATTLE CREEK	Replace Deteriorated Underground Primary ; Customers	43
35	LVD Lines Rehabilitation	FAIL 336 BUTZ RD, BRN Rotted Pole	0	1	Project	Imminent Rehabilitation	BRONSON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
36	LVD Lines Rehabilitation	FAIL MURNER_VAN TYLE MILLBOCKER ESIC OHL	164	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
37	LVD Lines Rehabilitation	FAIL MURNER_VAN TYLE OROURKE BLVD RLO OH	325	1	Project	Imminent Rehabilitation	GAYLORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
38	LVD Lines Rehabilitation	FA-NOBLE_WHITNEY secondary relocate;FLRE	40	1	Project	Imminent Rehabilitation	SIMS	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
39	LVD Lines Rehabilitation	FA-PULLMAN-CHICORA 103RDAve &50thst FRRE	5	1	Project	Imminent Rehabilitation	CLYDE	Retire and Remove Unused Assets; Customers	58
40	LVD Lines Rehabilitation	FA-PULLMAN-CHICORA 110THAVE &52NDST FRRE	13	1	Project	Imminent Rehabilitation	CLYDE	Retire and Remove Unused Assets; Customers	58
41	LVD Lines Rehabilitation	FA-PULLMAN-CHICORA 455 50TH ST OHC1	8	1	Project	Imminent Rehabilitation	CLYDE	Correct Conductor Clearance Violation ; Customers	20
42	LVD Lines Rehabilitation	FA-VOLT-1300 MICHIGAN AVE, TIPTON	18	1	Project	Imminent Rehabilitation	MANCHESTER	Improve Secondary Voltage ; Customers	5
43	LVD Lines Rehabilitation	FA-VOLT-7455 INDIAN RD, TEMPERANCE	6	1	Project	Imminent Rehabilitation	BEDFORD	Improve Secondary Voltage ; Customers	5
44	LVD Lines Rehabilitation	Fix service clearance issue	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Correct Conductor Clearance Violation ; Customers	24
45	LVD Lines Rehabilitation	IVANREST-HARLO LCP 556 ESIC UGL	48	1	Project	Imminent Rehabilitation	GRANDVILLE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
46	LVD Lines Rehabilitation	NASH RD S/O BURDICKVILLE RD MAPLE CITY	15	1	Project	Imminent Rehabilitation	CLEVELAND	Correct Conductor Clearance Violation ; Customers	24
47	LVD Lines Rehabilitation	-ODCE 4124 GRANDVIEW TER SW GVL*RP PADMT	1	1	Project	Imminent Rehabilitation	GRANDVILLE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
48	LVD Lines Rehabilitation	OHC2 2187 E LAKE MITCHELL DR	13	1	Project	Imminent Rehabilitation	CADILLAC	Correct Conductor Clearance Violation ; Customers	24
49	LVD Lines Rehabilitation	OVLD – 4535 Sarafield St NE Grand Rapids	8	1	Project	Imminent Rehabilitation	PLAINFIELD	Improve Secondary Voltage ; Customers	5
50	LVD Lines Rehabilitation	RHAB23 4141 DIXIE,SAMUEL 19-22 ESIC UGL	94	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Underground Primary ; Customers	43
51	LVD Lines Rehabilitation	RLBY TALLMAN_WACOUSTA LCP 493 ESIC OHL	13	1	Project	Imminent Rehabilitation	WESTPHALIA	Replace Deteriorated Pole ; Customers	242
52	LVD Lines Rehabilitation	SYSP HARRIET_HARRIET LCP 607	16	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Pole Top Equipment ; Customers	206
53		**LVD Lines Rehabilitation Subtotal**	**1,626**						
54		**Imminent Rehabilitation Total**	**15,120**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	Modem Replacements	**2,998**	800	Modems	Modem Replacement	STATEWIDE	Avoid Obsolescence	
2	LVD Lines Rehabilitation	Meter Voltage Anomalies	**6,386**	N/A		Meter Voltage Anomalies	STATEWIDE	Regulatory Compliance	
3	LVD Lines Rehabilitation	FLRE SUBSF ALDEN CLAM LCP 359	6	1	Project	Subsurface Transformer Replacement	FOREST HOME	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
4	LVD Lines Rehabilitation	FLRE SUBSF ALDEN TORCH LCP 4340	7	1	Project	Subsurface Transformer Replacement	MILTON	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
5	LVD Lines Rehabilitation	FLRE SUBSF ALDEN TORCH LCP 310	46	1	Project	Subsurface Transformer Replacement	MILTON	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
6	LVD Lines Rehabilitation	FLRE SUBSF BOMAN COUTANT LCP 431	196	1	Project	Subsurface Transformer Replacement	FLUSHING	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
7	LVD Lines Rehabilitation	FLRE SUBSF BOON RD ROUND LK LCP 796	58	1	Project	Subsurface Transformer Replacement	HARING	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
8	LVD Lines Rehabilitation	FLRE SUBSF CADILLAC HOSPITAL LCP 685	32	1	Project	Subsurface Transformer Replacement	CADILLAC	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
9	LVD Lines Rehabilitation	FLRE SUBSF EAST BAY WEST BAY LCP 059	16	1	Project	Subsurface Transformer Replacement	TRAVERSE CITY	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
10	LVD Lines Rehabilitation	FLRE SUBSF HOSPITAL ELMWOOD LCP 250	34	1	Project	Subsurface Transformer Replacement	TRAVERSE CITY	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
11	LVD Lines Rehabilitation	FLRE SUBSF HUNT ROAD_HOSPITAL LCP 0601	4	1	Project	Subsurface Transformer Replacement	ADRIAN	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
12	LVD Lines Rehabilitation	FLRE SUBSF LEELANAU OMENA BAY LCP 692	4	1	Project	Subsurface Transformer Replacement	LEELANAU	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
13	LVD Lines Rehabilitation	FLRE SUBSF SCHUSS MOUNTAIN PUMP LCP 210	20	1	Project	Subsurface Transformer Replacement	KEARNEY	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
14	LVD Lines Rehabilitation	FLRE SUBSF SCHUSS MTN CHALET SUB	66	1	Project	Subsurface Transformer Replacement	KEARNEY	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
15	LVD Lines Rehabilitation	FLRE SUBSF SILVER LAKE SECOR LCP 421	22	1	Project	Subsurface Transformer Replacement	GREEN LK	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
16	LVD Lines Rehabilitation	FLRE SUBSF SILVER LAKE SECOR LCP 422	13	1	Project	Subsurface Transformer Replacement	GREEN LK	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
17	LVD Lines Rehabilitation	FLRE SUBSF SILVER LAKE TWIN LAKE LCP 397	4	1	Project	Subsurface Transformer Replacement	GARFIELD	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	2
		LVD Lines Rehabilitation Subtotal (Subsurface Transformers)	**528**						
		LVD Lines Rehabilitation Total	**25,032**						

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	Reliability								
1	LVD Repetitive Outage	RPOUT14 Pennfield/Pennfield LCP504	387	1	Project	Repetitive Outage Projects	PENNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	6,138
2	LVD Repetitive Outage	RPOUT KRAFT AVENUE ACQUEST LCP 734 UGL	78	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	6,208
3	LVD Repetitive Outage	SYSP17 COTTAGE GROVE_PREVO LCP 998	45	1	Project	Repetitive Outage Projects	KAWKAWLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	40,000
4	LVD Repetitive Outage	RPOUT18 BEAVERTON/ROSS LCP 325	110	1	Project	Repetitive Outage Projects	BEAVERTON	Reduce Repeated Outages; Customer-outage-minutes avoided	47,580
5	LVD Repetitive Outage	SYSP ST CHARLES/FERGUS LCP 319 & 310	110	1	Project	Repetitive Outage Projects	ST CHARLES	Reduce Repeated Outages; Customer-outage-minutes avoided	692
6	LVD Repetitive Outage	SYSP19 Midland_Commercial LCP 342	5	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	8,165
7	LVD Repetitive Outage	SYSP19 Larkin_N Midland LCP 404	8	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	300
8	LVD Repetitive Outage	RPOUT Renton - Watkins First Zone	13	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	23,529
9	LVD Repetitive Outage	RPOUT19Lovejoy Braden Steinacker Recl	45	1	Project	Repetitive Outage Projects	ARGENTINE	Reduce Repeated Outages; Customer-outage-minutes avoided	39,642
10	LVD Repetitive Outage	RPOUT STANDALE_STANDALE LCP 356	52	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	40,176
11	LVD Repetitive Outage	RPOUT HOPKINS MONTEREY LCP 900	30	1	Project	Repetitive Outage Projects	HOPKINS	Reduce Repeated Outages; Customer-outage-minutes avoided	24,900
12	LVD Repetitive Outage	RPOUT ASH ROAD_STERLING RD	52	1	Project	Repetitive Outage Projects	LITCHFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	24,000
13	LVD Repetitive Outage	SYSP MASON SOUTH ST. FUSE COORDINATION	49	1	Project	Repetitive Outage Projects	MASON	Reduce Repeated Outages; Customer-outage-minutes avoided	7,506
14	LVD Repetitive Outage	SYSP ALCONA DAM_GLENNIE	8	1	Project	Repetitive Outage Projects	CURTIS	Reduce Repeated Outages; Customer-outage-minutes avoided	85,620
15	LVD Repetitive Outage	RPOUT NORGE MACHINE LINCOLN	19	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	60
16	LVD Repetitive Outage	RPOUT CEMI12 QUINCY_QUINCY OHL	154	1	Project	Repetitive Outage Projects	QUINCY	Reduce Repeated Outages; Customer-outage-minutes avoided	88,955
17	LVD Repetitive Outage	RPOUT MIDDLEVILLE LAFAYETTE SUB	36	1	Project	Repetitive Outage Projects	MIDDLEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	41,446
18	LVD Repetitive Outage	RPOUT Ft Custer - Hill Brady LCP 254	90	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	3,750
19	LVD Repetitive Outage	RPOUT Bluewater-Colony LCP 173-Poles	160	1	Project	Repetitive Outage Projects	ST JOHNS	Reduce Repeated Outages; Customer-outage-minutes avoided	6,300
20	LVD Repetitive Outage	RPOUT Dewitt-Geneva Lk LCP Sub	28	1	Project	Repetitive Outage Projects	DEWITT	Reduce Repeated Outages; Customer-outage-minutes avoided	152,340
21	LVD Repetitive Outage	RPOUT HOMER_INDUSTRIAL LCP 685	19	1	Project	Repetitive Outage Projects	HOMER	Reduce Repeated Outages; Customer-outage-minutes avoided	310
22	LVD Repetitive Outage	RPOUT Otisville/Irish Rd LCP 591	68	1	Project	Repetitive Outage Projects	OTISVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	70,837
23	LVD Repetitive Outage	RPOUT LOGISTIC FELCH LCP 837	161	1	Project	Repetitive Outage Projects	ZEELAND	Reduce Repeated Outages; Customer-outage-minutes avoided	23,968
24	LVD Repetitive Outage	RPOUT BILMAR PEIRCE LCP 725	117	1	Project	Repetitive Outage Projects	BLENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	12,770
25	LVD Repetitive Outage	RPOUT Haskelite_3 Mile LCP 425	50	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	34,866
26	LVD Repetitive Outage	RPOUT Colon_Colon LCP 947	118	1	Project	Repetitive Outage Projects	COLON	Reduce Repeated Outages; Customer-outage-minutes avoided	76,392
27	LVD Repetitive Outage	RPOUT WEST RIVER_GRAND RIVER LCP-737	5	1	Project	Repetitive Outage Projects	PLAINFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	3,858
28	LVD Repetitive Outage	RPOUT ROCKFORD_WOVERINE LCP-333	12	1	Project	Repetitive Outage Projects	ROCKFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	107,757
29	LVD Repetitive Outage	RPOUT ST CHARLES/SAGINAW LCP 604	108	1	Project	Repetitive Outage Projects	ST CHARLES	Reduce Repeated Outages; Customer-outage-minutes avoided	21,393
30	LVD Repetitive Outage	RPOUT Belding_City LCP 513 UG Tie Line	330	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	31,000
31	LVD Repetitive Outage	RPOUT YORKVILLE_BAYVIEW LCP 144 ESIC OHL	270	1	Project	Repetitive Outage Projects	RICHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	106,272
32	LVD Repetitive Outage	RPOUT Alder Creek - Lee Lake LCP 303	58	1	Project	Repetitive Outage Projects	UNION CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	143,974
33	LVD Repetitive Outage	RPOUT 11435 40th Ave - Cable Fault UGL	137	1	Project	Repetitive Outage Projects	ALLENDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	5,760
34	LVD Repetitive Outage	RPOUT-PECK-ROAD_WISE-ROAD-LCP-0024	35	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	52,800
35	LVD Repetitive Outage	RPOUT BENTHEIM_140TH AVENUE LCP 117	33	1	Project	Repetitive Outage Projects	SALEM	Reduce Repeated Outages; Customer-outage-minutes avoided	54,493
36	LVD Repetitive Outage	RPOUT VIRGINIA PARK_CASTLE LCP CKT	42	1	Project	Repetitive Outage Projects	HOLLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	295,323
37	LVD Repetitive Outage	RPOUT MILLGROVE ALGNHYDR LCP 378 PT 2	178	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	152,091
38	LVD Repetitive Outage	RPOUT DEAN ROAD-SHANNON LAKE LCP151	15	1	Project	Repetitive Outage Projects	ARGENTINE	Reduce Repeated Outages; Customer-outage-minutes avoided	594,270
39	LVD Repetitive Outage	RPOUT BROADMOOR_NORTH LCP 306	41	1	Project	Repetitive Outage Projects	KENTWOOD	Reduce Repeated Outages; Customer-outage-minutes avoided	200
40	LVD Repetitive Outage	RPOUT HASKELITE_ANN ST LCP 148 ATR RELOC	30	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	174,000
41	LVD Repetitive Outage	RPOUT N MUSKEGON STATE PARK LCP 38	139	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	27,100
42	LVD Repetitive Outage	RPOUT KENTWOOD_PRINCETON LCP 0639	48	1	Project	Repetitive Outage Projects	KENTWOOD	Reduce Repeated Outages; Customer-outage-minutes avoided	9,215
43	LVD Repetitive Outage	RPOUT MILL GROVE_ALLEGAN HYDRO LCP855	80	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	4,664
44	LVD Repetitive Outage	RPOUT WILLIAMS_CRESENT LCP 395	128	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	156,784
45	LVD Repetitive Outage	FAIL24READING-CAMBRIA-7510 READING RD-RE	34	1	Project	Repetitive Outage Projects	READING	Reduce Repeated Outages; Customer-outage-minutes avoided	692,254
46	LVD Repetitive Outage	SYSP TALLMAN_WACOUSTA LCP 188	43	1	Project	Repetitive Outage Projects	WESTPHALIA	Reduce Repeated Outages; Customer-outage-minutes avoided	16,471
47	LVD Repetitive Outage	SYSP WEST FENTON OVERPASS LCP#560 UG	76	1	Project	Repetitive Outage Projects	FENTON	Reduce Repeated Outages; Customer-outage-minutes avoided	279,720
48	LVD Repetitive Outage	RPOUT AGNEW_WEYBURN LCP 368	16	1	Project	Repetitive Outage Projects	GRAND HAVEN	Reduce Repeated Outages; Customer-outage-minutes avoided	4,680
49	LVD Repetitive Outage	RPOUT PIGEON LAKE_OLIVE LCP 531	7	1	Project	Repetitive Outage Projects	PARK	Reduce Repeated Outages; Customer-outage-minutes avoided	2,429
50	LVD Repetitive Outage	RPOUT WILLIAMS_ELY LCP 375	87	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	10,717
		LVD Repetitive Outages Subtotal	**3,962**						

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	Reliability								
1	LVD Repetitive Outage	RPOUT TAMARACK_AMBLE LCP 521	209	1	Project	Repetitive Outage Projects	LAKEVIEW	Reduce Repeated Outages; Customer-outage-minutes avoided	7,200
2	LVD Repetitive Outage	RPOUT NORTH LANSING_LABORATORY LCP 027	42	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	20,708
3	LVD Repetitive Outage	RPOUT TEXAS_EAGLE LAKE LCP SUB	75	1	Project	Repetitive Outage Projects	MATTAWAN	Reduce Repeated Outages; Customer-outage-minutes avoided	1,134,708
4	LVD Repetitive Outage	RPOUT LCP 472-40 LAKE LEANN_BUNDY HILL	64	1	Project	Repetitive Outage Projects	MOSCOW	Reduce Repeated Outages; Customer-outage-minutes avoided	17,130
5	LVD Repetitive Outage	RPOUT GREENVILLE_WASHINGTON ST	212	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	78,664
6	LVD Repetitive Outage	RPOUT TRUFANT_MASTON LAKE LCP 206	487	1	Project	Repetitive Outage Projects	MAPLE VALLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	15,295
7	LVD Repetitive Outage	RPOUT MULLINS_ROYAL VISTA LCP 312	47	1	Project	Repetitive Outage Projects	WALKER	Reduce Repeated Outages; Customer-outage-minutes avoided	83,100
8	LVD Repetitive Outage	RPOUT DIMONDALE_DIMONDALE LCP 878	19	1	Project	Repetitive Outage Projects	DIMONDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	7,000
9	LVD Repetitive Outage	RPOUT HOGSBACK_HOLT ROAD LCP SUB	7	1	Project	Repetitive Outage Projects	DELHI	Reduce Repeated Outages; Customer-outage-minutes avoided	66,811
10	LVD Repetitive Outage	RPOUT PIGEON LAKE_OLIVE LCP 547	11	1	Project	Repetitive Outage Projects	PARK	Reduce Repeated Outages; Customer-outage-minutes avoided	5,339
11	LVD Repetitive Outage	RPOUT24 ROSEBUSH STVNSON LK LCP 221	153	1	Project	Repetitive Outage Projects	ROSEBUSH	Reduce Repeated Outages; Customer-outage-minutes avoided	1,815
12	LVD Repetitive Outage	RPOUT24 Bullock Stewart LCP918	28	1	Project	Repetitive Outage Projects	LEE	Reduce Repeated Outages; Customer-outage-minutes avoided	12,556
13	LVD Repetitive Outage	RPOUT LEITH STREET_WESTERN ROAD LCP 519	53	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	2,735
14	LVD Repetitive Outage	RPOUT TEXAS_EAGLE LAKE LCP 760	130	1	Project	Repetitive Outage Projects	MATTAWAN	Reduce Repeated Outages; Customer-outage-minutes avoided	16,807
15	LVD Repetitive Outage	RPOUT SUNFIELD_SUNFIELD LCP 0729	19	1	Project	Repetitive Outage Projects	SUNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	5,000
16	LVD Repetitive Outage	RPOUT HARPER ROAD_ARENS LCP 363	50	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	58,680
17	LVD Repetitive Outage	RLBY DEAN ROAD_SHANNOON LAKE LCP 648	45	1	Project	Repetitive Outage Projects	HARTLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	19,391
18	LVD Repetitive Outage	RPOUT WAYLAND_WAYLAND LCP 0684	5	1	Project	Repetitive Outage Projects	WAYLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	178,994
19	LVD Repetitive Outage	RPOUT TWIN LAKE_TWIN LAKE LCP 494	31	1	Project	Repetitive Outage Projects	HOLTON	Reduce Repeated Outages; Customer-outage-minutes avoided	30,000
20	LVD Repetitive Outage	RPOUT MAPLE GROVE_SUMMIT AVENUE LCP 390	77	1	Project	Repetitive Outage Projects	MUSKEGON HTS	Reduce Repeated Outages; Customer-outage-minutes avoided	109,217
21	LVD Repetitive Outage	RPOUT DEWITT_DEWITT LCP 570	12	1	Project	Repetitive Outage Projects	DEWITT	Reduce Repeated Outages; Customer-outage-minutes avoided	10,000
22	LVD Repetitive Outage	RPOUT JUDD ROAD_OTTAWA LCP 284	46	1	Project	Repetitive Outage Projects	BURTON	Reduce Repeated Outages; Customer-outage-minutes avoided	2,939
23	LVD Repetitive Outage	RPOUT COMSTOCK_TUNIER LCP 891	100	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	2,494
24	LVD Repetitive Outage	RPOUT PICKEREL_INDIAN LAKE LCP 803	366	1	Project	Repetitive Outage Projects	PORTAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	26,902
25	LVD Repetitive Outage	RPOUT WHITTUM_ROYSTON LCP 279	98	1	Project	Repetitive Outage Projects	EATON RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	22,240
26	LVD Repetitive Outage	RPOUT Knight_Rosemary LCP 602 ESIC OHL	8	1	Project	Repetitive Outage Projects	BAY CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	81,453
27	LVD Repetitive Outage	RPOUT MIDDLEVILLE_BUSINESS LCP 0207	3	1	Project	Repetitive Outage Projects	MIDDLEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	200
28	LVD Repetitive Outage	RPOUT ALAMO_Owen LCP Sub	5	1	Project	Repetitive Outage Projects	PINE GROVE	Reduce Repeated Outages; Customer-outage-minutes avoided	20,298
29	LVD Repetitive Outage	RPOUT WARNER_BURCHETT LCP 454	191	1	Project	Repetitive Outage Projects	PRAIRIEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	78,774
30	LVD Repetitive Outage	RPOUT ALAMO_PINE GROVE LCP 646	55	1	Project	Repetitive Outage Projects	PINE GROVE	Reduce Repeated Outages; Customer-outage-minutes avoided	43,372
31	LVD Repetitive Outage	PULLMAN-CHICORA ELECTRONIC RECLOSERS	66	1	Project	Repetitive Outage Projects	CLYDE	Reduce Repeated Outages; Customer-outage-minutes avoided	3
32	LVD Repetitive Outage	PULLMAN-PULLMAN ELECTRONIC RECLOSERS	58	1	Project	Repetitive Outage Projects	CLYDE	Reduce Repeated Outages; Customer-outage-minutes avoided	15,072
33	LVD Repetitive Outage	RPOUT PETTIS ROAD_PETTIS RD LCP 229	5	1	Project	Repetitive Outage Projects	ADA	Reduce Repeated Outages; Customer-outage-minutes avoided	85,917
34	LVD Repetitive Outage	RPOUT NUNICA_LEONARD LCP 505	18	1	Project	Repetitive Outage Projects	POLKTON	Reduce Repeated Outages; Customer-outage-minutes avoided	9,887
35	LVD Repetitive Outage	RPOUT NUNICA_LEONARD LCP 122	17	1	Project	Repetitive Outage Projects	POLKTON	Reduce Repeated Outages; Customer-outage-minutes avoided	7,525
36	LVD Repetitive Outage	RPOUT Belding_Cooks Corners LCP 689	143	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	20,000
37	LVD Repetitive Outage	RPOUT CASCO_HAWKHEAD LCP 466	10	1	Project	Repetitive Outage Projects	CASCO	Reduce Repeated Outages; Customer-outage-minutes avoided	4,219
38	LVD Repetitive Outage	RPOUT NUNICA_LEONARD LCP 125	20	1	Project	Repetitive Outage Projects	POLKTON	Reduce Repeated Outages; Customer-outage-minutes avoided	11,557
39	LVD Repetitive Outage	RPOUT Middleton Newark LCP884	21	1	Project	Repetitive Outage Projects	MAPLE RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	3,590
40	LVD Repetitive Outage	RPOUT SPRING LAKE_SPRING LAKE LCP 281	37	1	Project	Repetitive Outage Projects	SPRING LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	7,200
41	LVD Repetitive Outage	RPOUT CEDAR SPRINGS_EDGERTON LCP 300	7	1	Project	Repetitive Outage Projects	CEDAR SPRINGS	Reduce Repeated Outages; Customer-outage-minutes avoided	35,332
42	LVD Repetitive Outage	RPOUT HESPERIA_HESPERIA LCP 797	26	1	Project	Repetitive Outage Projects	HESPERIA	Reduce Repeated Outages; Customer-outage-minutes avoided	24,390
43	LVD Repetitive Outage	RPOUT 4532 Rives Eaton Rd, Rives	857	1	Project	Repetitive Outage Projects	RIVES	Reduce Repeated Outages; Customer-outage-minutes avoided	123,381
44	LVD Repetitive Outage	RPOUT HYDE PARK_ROSS LCP 209	12	1	Project	Repetitive Outage Projects	FRUITLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	16,833
45	LVD Repetitive Outage	RPOUT NUNICA_WILSON LCP 531	18	1	Project	Repetitive Outage Projects	RAVENNA	Reduce Repeated Outages; Customer-outage-minutes avoided	282,343
46	LVD Repetitive Outage	RPOUT APPLE_CHATTERSON ROAD LCP 605	26	1	Project	Repetitive Outage Projects	EGELSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	22,770
47	LVD Repetitive Outage	RPOUT DONTZ ROAD_KOTT ROAD LCP 515	42	1	Project	Repetitive Outage Projects	MANISTEE	Reduce Repeated Outages; Customer-outage-minutes avoided	33,735
48	LVD Repetitive Outage	RPOUT ROTHBURY_NEW ERA LCP 640	3	1	Project	Repetitive Outage Projects	NEW ERA	Reduce Repeated Outages; Customer-outage-minutes avoided	4,424
49	LVD Repetitive Outage	RPOUT EVANSTON_EVANSTON LCP 565	16	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	1,678
50	LVD Repetitive Outage	RPOUT_ENSLEY_BAPTIST LAKE_LCP 754	20	1	Project	Repetitive Outage Projects	ENSLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	20,395
51		**LVD Repetitive Outages Subtotal**	**4,070**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outage	RPOUT HOMER-INDUSTRIAL LCP 659	90	1	Project	Repetitive Outage Projects	HOMER	Reduce Repeated Outages; Customer-outage-minutes avoided	74,462
2	LVD Repetitive Outage	RPOUT ATHENS-SHERWOOD LCP 137	90	1	Project	Repetitive Outage Projects	ATHENS	Reduce Repeated Outages; Customer-outage-minutes avoided	12,583
3	LVD Repetitive Outage	RPOUT CENTREVILLE-BUSINESS LCP 293	90	1	Project	Repetitive Outage Projects	CENTREVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	171,440
4	LVD Repetitive Outage	RPOUT STANWOOD-RIVERSWAY LCP 928	90	1	Project	Repetitive Outage Projects	COLFAX	Reduce Repeated Outages; Customer-outage-minutes avoided	69,996
5	LVD Repetitive Outage	RPOUT PEACH RIDGE-KENOWA LCP 390	90	1	Project	Repetitive Outage Projects	SPARTA	Reduce Repeated Outages; Customer-outage-minutes avoided	32,747
6	LVD Repetitive Outage	RPOUT PRESCOTT-LOGAN LCP 169	90	1	Project	Repetitive Outage Projects	PRESCOTT	Reduce Repeated Outages; Customer-outage-minutes avoided	25,986
7	LVD Repetitive Outage	RPOUT SURREY-SURREY LCP 718	90	1	Project	Repetitive Outage Projects	FARWELL	Reduce Repeated Outages; Customer-outage-minutes avoided	15,274
8	LVD Repetitive Outage	RPOUT LAWRENCE-CHRISTIE LAKE LCP 687	90	1	Project	Repetitive Outage Projects	LAWRENCE	Reduce Repeated Outages; Customer-outage-minutes avoided	68,599
9	LVD Repetitive Outage	RPOUT FREEPORT-CARLTON CENTER LCP 484	90	1	Project	Repetitive Outage Projects	FREEPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	27,438
10	LVD Repetitive Outage	RPOUT BATES-ACME LCP 226	90	1	Project	Repetitive Outage Projects	ACME	Reduce Repeated Outages; Customer-outage-minutes avoided	7,408
11	LVD Repetitive Outage	RPOUT SCIPIO-MOSHERVILLE LCP 356	90	1	Project	Repetitive Outage Projects	SCIPIO	Reduce Repeated Outages; Customer-outage-minutes avoided	120,310
12	LVD Repetitive Outage	RPOUT ONEKAMA-ONEKAMA LCP 113	90	1	Project	Repetitive Outage Projects	ONEKAMA	Reduce Repeated Outages; Customer-outage-minutes avoided	68,120
13	LVD Repetitive Outage	RPOUT MENDON-PINHOOK LCP 442	90	1	Project	Repetitive Outage Projects	MENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	15,677
14	LVD Repetitive Outage	RPOUT SCIPIO-POPE ROAD LCP 831	90	1	Project	Repetitive Outage Projects	MOSCOW	Reduce Repeated Outages; Customer-outage-minutes avoided	207,394
15	LVD Repetitive Outage	RPOUT DEWITT-DEWITT LCP 740	90	1	Project	Repetitive Outage Projects	DEWITT	Reduce Repeated Outages; Customer-outage-minutes avoided	9,201
16	LVD Repetitive Outage	RPOUT PETTIS ROAD-HONEY CREEK LCP CKT	90	1	Project	Repetitive Outage Projects	ADA	Reduce Repeated Outages; Customer-outage-minutes avoided	51,745
17	LVD Repetitive Outage	RPOUT WAKESHMA-FULTON LCP 603	90	1	Project	Repetitive Outage Projects	WAKESHMA	Reduce Repeated Outages; Customer-outage-minutes avoided	17,751
18	LVD Repetitive Outage	RPOUT SPRINGPORT-DEVEREAUX LCP 426	90	1	Project	Repetitive Outage Projects	SPRINGPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	25,349
19	LVD Repetitive Outage	RPOUT BLUE WATER-SCOTT ROAD LCP 452	90	1	Project	Repetitive Outage Projects	ST JOHNS	Reduce Repeated Outages; Customer-outage-minutes avoided	38,340
20	LVD Repetitive Outage	RPOUT ABBE-ABBE LCP 328	90	1	Project	Repetitive Outage Projects	MENTOR	Reduce Repeated Outages; Customer-outage-minutes avoided	84,156
21	LVD Repetitive Outage	RPOUT FINE LAKE-DOWLING LCP 433	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	6,894
22	LVD Repetitive Outage	RPOUT BURTCH ROAD-BURTCH ROAD LCP 734	90	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,691
23	LVD Repetitive Outage	RPOUT LOMBARD-LOMBARD LCP 281	90	1	Project	Repetitive Outage Projects	ALBION	Reduce Repeated Outages; Customer-outage-minutes avoided	51,398
24	LVD Repetitive Outage	RPOUT FRANKFORT-CRYSTALLIA LCP 5032	90	1	Project	Repetitive Outage Projects	FRANKFORT	Reduce Repeated Outages; Customer-outage-minutes avoided	57,696
25	LVD Repetitive Outage	RPOUT BURR OAK-DOUGLAS LCP 842	90	1	Project	Repetitive Outage Projects	BURR OAK	Reduce Repeated Outages; Customer-outage-minutes avoided	73,482
26	LVD Repetitive Outage	RPOUT OBERLIN-BENMARK LCP 841	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	51,288
27	LVD Repetitive Outage	RPOUT HOMESTEAD-BEULAH LCP 186	90	1	Project	Repetitive Outage Projects	BEULAH	Reduce Repeated Outages; Customer-outage-minutes avoided	27,927
28	LVD Repetitive Outage	RPOUT BATH-BATH LCP 215	90	1	Project	Repetitive Outage Projects	OLIVE	Reduce Repeated Outages; Customer-outage-minutes avoided	22,739
29	LVD Repetitive Outage	RPOUT NUNICA-WILSON LCP 646	90	1	Project	Repetitive Outage Projects	RAVENNA	Reduce Repeated Outages; Customer-outage-minutes avoided	94,712
30	LVD Repetitive Outage	RPOUT CLEAR LAKE-WATERLOO LCP 174	90	1	Project	Repetitive Outage Projects	WATERLOO	Reduce Repeated Outages; Customer-outage-minutes avoided	236,071
31	LVD Repetitive Outage	RPOUT PARMA-PARMA LCP 130	90	1	Project	Repetitive Outage Projects	PARMA	Reduce Repeated Outages; Customer-outage-minutes avoided	22,450
32	LVD Repetitive Outage	RPOUT SYLVAN-CITY LCP 743	90	1	Project	Repetitive Outage Projects	CHELSEA	Reduce Repeated Outages; Customer-outage-minutes avoided	132,723
33	LVD Repetitive Outage	RPOUT SHERIDAN-FENWICK LCP 16	90	1	Project	Repetitive Outage Projects	SHERIDAN	Reduce Repeated Outages; Customer-outage-minutes avoided	107,517
34	LVD Repetitive Outage	RPOUT FENNVILLE-COMMERCIAL LCP 878	90	1	Project	Repetitive Outage Projects	FENNVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	90,365
35	LVD Repetitive Outage	RPOUT ENGLISHVILLE-ENGLISHVILLE LCP 455	90	1	Project	Repetitive Outage Projects	SPARTA	Reduce Repeated Outages; Customer-outage-minutes avoided	23,999
36	LVD Repetitive Outage	RPOUT STANTON-STANTON LCP 263	90	1	Project	Repetitive Outage Projects	STANTON	Reduce Repeated Outages; Customer-outage-minutes avoided	48,975
37	LVD Repetitive Outage	RPOUT ALAMO-OWEN LCP CKT	90	1	Project	Repetitive Outage Projects	OSHTEMO	Reduce Repeated Outages; Customer-outage-minutes avoided	257,136
38	LVD Repetitive Outage	RPOUT OSHTEMO-HURD LCP 441	90	1	Project	Repetitive Outage Projects	OSHTEMO	Reduce Repeated Outages; Customer-outage-minutes avoided	44,158
39	LVD Repetitive Outage	RPOUT VANDERCOOK LAKE-HAGUE ROAD LCP 806	90	1	Project	Repetitive Outage Projects	LIBERTY	Reduce Repeated Outages; Customer-outage-minutes avoided	105,562
40	LVD Repetitive Outage	RPOUT HOLTON-MAPLE ISLAND LCP 658	90	1	Project	Repetitive Outage Projects	FREMONT	Reduce Repeated Outages; Customer-outage-minutes avoided	88,062
41	LVD Repetitive Outage	RPOUT BATTEESE-MUNITH LCP 9461	90	1	Project	Repetitive Outage Projects	WATERLOO	Reduce Repeated Outages; Customer-outage-minutes avoided	21,846
42	LVD Repetitive Outage	RPOUT SHERIDAN-SIDNEY LCP 175	90	1	Project	Repetitive Outage Projects	SHERIDAN	Reduce Repeated Outages; Customer-outage-minutes avoided	21,254
43	LVD Repetitive Outage	RPOUT COOKE DAM-VILLAGE LCP 805	90	1	Project	Repetitive Outage Projects	PLAINFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	58,675
44	LVD Repetitive Outage	RPOUT FINE LAKE-BRISTOL LCP 417	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	4,923
45	LVD Repetitive Outage	RPOUT JOPPA-BECKLEY LCP 868	90	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	48,132
46	LVD Repetitive Outage	RPOUT KNIGHT-FARLEY LCP 784	90	1	Project	Repetitive Outage Projects	GILFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	33,152
47	LVD Repetitive Outage	RPOUT DEERFIELD-RODESILER LCP 5	90	1	Project	Repetitive Outage Projects	DEERFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	22,860
48	LVD Repetitive Outage	RPOUT SCOTTVILLE-US-31 LCP 397	90	1	Project	Repetitive Outage Projects	FREESOIL	Reduce Repeated Outages; Customer-outage-minutes avoided	14,875
49	LVD Repetitive Outage	RPOUT HAGADORN-HAGADORN LCP 82	90	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	16,040
50	LVD Repetitive Outage	RPOUT LOCH ERIN-PENTECOST LCP 353	90	1	Project	Repetitive Outage Projects	FRANKLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	142,307
51		**LVD Repetitive Outages Subtotal**	**4,500**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outage	RPOUT TWILIGHT-RICHLAND FARMS LCP 952	90	1	Project	Repetitive Outage Projects	RICHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	29,786
2	LVD Repetitive Outage	RPOUT CLARE-FARWELL LCP 292	90	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoided	22,645
3	LVD Repetitive Outage	RPOUT BURR OAK-DOUGLAS LCP 917	90	1	Project	Repetitive Outage Projects	BURR OAK	Reduce Repeated Outages; Customer-outage-minutes avoided	20,659
4	LVD Repetitive Outage	RPOUT SUNFIELD-SUNFIELD LCP 729	90	1	Project	Repetitive Outage Projects	SUNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	31,764
5	LVD Repetitive Outage	RPOUT SCOTTS-WHITE LCP 272	90	1	Project	Repetitive Outage Projects	CHARLESTON	Reduce Repeated Outages; Customer-outage-minutes avoided	11,357
6	LVD Repetitive Outage	RPOUT LEHRING-COLE ROAD LCP 647	90	1	Project	Repetitive Outage Projects	BYRON	Reduce Repeated Outages; Customer-outage-minutes avoided	74,963
7	LVD Repetitive Outage	RPOUT RAVINE-PATTERSON LCP 615	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	18,879
8	LVD Repetitive Outage	RPOUT GRAYLING-RIVER LCP 148	90	1	Project	Repetitive Outage Projects	GRAYLING	Reduce Repeated Outages; Customer-outage-minutes avoided	27,118
9	LVD Repetitive Outage	RPOUT KENT CITY-CASNOVIA LCP 895	90	1	Project	Repetitive Outage Projects	CASNOVIA	Reduce Repeated Outages; Customer-outage-minutes avoided	5,767
10	LVD Repetitive Outages	RPOUT ARTHUR-BERLIN LCP 967	80	1	Project	Repetitive Outage Projects	POLKTON	Reduce Repeated Outages; Customer-outage-minutes avoided	29,605
11	LVD Repetitive Outages	RPOUT HANOVER-PULASKI LCP 886	90	1	Project	Repetitive Outage Projects	HANOVER	Reduce Repeated Outages; Customer-outage-minutes avoided	132,165
12	LVD Repetitive Outages	RPOUT FINE LAKE-BRISTOL LCP 493	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	25,740
13	LVD Repetitive Outages	RPOUT PALO-PALO LCP 244	90	1	Project	Repetitive Outage Projects	N PLAINS	Reduce Repeated Outages; Customer-outage-minutes avoided	73,192
14	LVD Repetitive Outages	RPOUT SMITH CREEK-WRIGHT LCP 5039	90	1	Project	Repetitive Outage Projects	WEST BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	18,821
15	LVD Repetitive Outages	RPOUT RODNEY-RODNEY LCP 452	90	1	Project	Repetitive Outage Projects	COLFAX	Reduce Repeated Outages; Customer-outage-minutes avoided	159,618
16	LVD Repetitive Outages	RPOUT BURTCH ROAD-WELCH LAKE LCP 266	90	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	320,770
17	LVD Repetitive Outages	RPOUT ST CHARLES-SAGINAW LCP 604	90	1	Project	Repetitive Outage Projects	ST CHARLES	Reduce Repeated Outages; Customer-outage-minutes avoided	43,306
18	LVD Repetitive Outages	RPOUT MENDON-KIRBY LCP 167	90	1	Project	Repetitive Outage Projects	MENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	6,815
19	LVD Repetitive Outages	RPOUT RAVENNA-RAVENNA LCP 17	90	1	Project	Repetitive Outage Projects	RAVENNA	Reduce Repeated Outages; Customer-outage-minutes avoided	24,235
20	LVD Repetitive Outages	RPOUT MARKER LAKE-KYSER ROAD LCP 184	90	1	Project	Repetitive Outage Projects	BOSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	22,322
21	LVD Repetitive Outages	RPOUT COIT AVENUE-RIFLE RANGE LCP 457	90	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	43,548
22	LVD Repetitive Outages	RPOUT FENTON-SILVER LAKE LCP 440	90	1	Project	Repetitive Outage Projects	FENTON	Reduce Repeated Outages; Customer-outage-minutes avoided	19,600
23	LVD Repetitive Outages	RPOUT MCBAIN-VOGEL CENTER LCP 200	90	1	Project	Repetitive Outage Projects	MCBAIN	Reduce Repeated Outages; Customer-outage-minutes avoided	10,096
24	LVD Repetitive Outages	RPOUT STOCKBRIDGE-MORTON LCP 456	90	1	Project	Repetitive Outage Projects	STOCKBRIDGE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,518
25	LVD Repetitive Outages	RPOUT HARRISON-HARRISON LCP 5883	90	1	Project	Repetitive Outage Projects	HARRISON	Reduce Repeated Outages; Customer-outage-minutes avoided	27,627
26	LVD Repetitive Outages	RPOUT ENGLISHVILLE-ENGLISHVILLE LCP 56	90	1	Project	Repetitive Outage Projects	SPARTA	Reduce Repeated Outages; Customer-outage-minutes avoided	56,934
27	LVD Repetitive Outages	RPOUT SWAN CREEK-MINING LCP 70	90	1	Project	Repetitive Outage Projects	CLYDE	Reduce Repeated Outages; Customer-outage-minutes avoided	86,774
28	LVD Repetitive Outages	RPOUT BELLEVUE-BELLEVUE LCP 77	90	1	Project	Repetitive Outage Projects	BELLEVUE	Reduce Repeated Outages; Customer-outage-minutes avoided	46,623
29	LVD Repetitive Outages	RPOUT MANTON-GILBERT LCP 346	90	1	Project	Repetitive Outage Projects	MANTON	Reduce Repeated Outages; Customer-outage-minutes avoided	27,375
30	LVD Repetitive Outages	RPOUT MAPLE CITY-CEDAR LCP 745	90	1	Project	Repetitive Outage Projects	CLEVELAND	Reduce Repeated Outages; Customer-outage-minutes avoided	84,342
31	LVD Repetitive Outages	RPOUT BAILEY-CHERRY LCP 259	90	1	Project	Repetitive Outage Projects	ASHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	18,294
32	LVD Repetitive Outages	RPOUT PEACOCK-STOLL ROAD LCP 475	90	1	Project	Repetitive Outage Projects	WOODHULL	Reduce Repeated Outages; Customer-outage-minutes avoided	42,716
33	LVD Repetitive Outages	RPOUT FOREMAN-VERGENNES LCP 334	90	1	Project	Repetitive Outage Projects	ADA	Reduce Repeated Outages; Customer-outage-minutes avoided	72,880
34	LVD Repetitive Outages	RPOUT BALCOM-BANKERS LCP 690	90	1	Project	Repetitive Outage Projects	HILLSDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	45,949
35	LVD Repetitive Outages	RPOUT RATIGAN-MURRAY LAKE LCP 557	90	1	Project	Repetitive Outage Projects	OTISCO	Reduce Repeated Outages; Customer-outage-minutes avoided	40,155
36	LVD Repetitive Outages	RPOUT CERESCO-RURAL LCP 53	90	1	Project	Repetitive Outage Projects	MARSHALL	Reduce Repeated Outages; Customer-outage-minutes avoided	24,884
37	LVD Repetitive Outages	RPOUT GLADWIN-BUZZELL LCP 311	90	1	Project	Repetitive Outage Projects	GLADWIN	Reduce Repeated Outages; Customer-outage-minutes avoided	18,784
38	LVD Repetitive Outages	RPOUT EDMORE-SIX LAKES LCP 878	90	1	Project	Repetitive Outage Projects	EDMORE	Reduce Repeated Outages; Customer-outage-minutes avoided	9,511
39	LVD Repetitive Outages	RPOUT CASINO-LEATON LCP 625	90	1	Project	Repetitive Outage Projects	UNION	Reduce Repeated Outages; Customer-outage-minutes avoided	29,445
40	LVD Repetitive Outages	RPOUT BITTERSWEET-RIVER ROAD LCP 747	90	1	Project	Repetitive Outage Projects	TROWBRIDGE	Reduce Repeated Outages; Customer-outage-minutes avoided	20,344
41	LVD Repetitive Outages	RPOUT HOLTON-MAPLE ISLAND LCP 496	90	1	Project	Repetitive Outage Projects	FREMONT	Reduce Repeated Outages; Customer-outage-minutes avoided	14,995
42	LVD Repetitive Outages	RPOUT LINCOLN-MIKADO LCP 799	90	1	Project	Repetitive Outage Projects	GREENBUSH	Reduce Repeated Outages; Customer-outage-minutes avoided	52,550
43	LVD Repetitive Outages	RPOUT WAYLAND-WAYLAND LCP 741	90	1	Project	Repetitive Outage Projects	WAYLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	33,326
44	LVD Repetitive Outages	RPOUT MERSON-PIKE LAKE LCP 689	90	1	Project	Repetitive Outage Projects	TROWBRIDGE	Reduce Repeated Outages; Customer-outage-minutes avoided	54,996
45	LVD Repetitive Outages	RPOUT PALO-PALO LCP 198	90	1	Project	Repetitive Outage Projects	N PLAINS	Reduce Repeated Outages; Customer-outage-minutes avoided	50,023
46	LVD Repetitive Outages	RPOUT READING-CAMBRIA LCP 670	90	1	Project	Repetitive Outage Projects	READING	Reduce Repeated Outages; Customer-outage-minutes avoided	29,058
47	LVD Repetitive Outages	RPOUT BREEDSVILLE-GRAND JUNCTION LCP 823	90	1	Project	Repetitive Outage Projects	COLUMBIA	Reduce Repeated Outages; Customer-outage-minutes avoided	7,122
48	LVD Repetitive Outages	RPOUT BEAVER-SEIDLERS LCP 76	90	1	Project	Repetitive Outage Projects	KAWKAWLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	19,107
49	LVD Repetitive Outages	RPOUT MACKINAW CITY-POND STREET LCP 542	90	1	Project	Repetitive Outage Projects	MACKINAW CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	30,025
50	LVD Repetitive Outages	RPOUT LOVEJOY-BRADEN LCP CKT	90	1	Project	Repetitive Outage Projects	ARGENTINE	Reduce Repeated Outages; Customer-outage-minutes avoided	651,310
51		**LVD Repetitive Outages Subtotal**	**4,490**						

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT BAGLEY-OTSEGO LAKE LCP 5545	90	1	Project	Repetitive Outage Projects	GAYLORD	Reduce Repeated Outages; Customer-outage-minutes avoided	18,389
2	LVD Repetitive Outages	RPOUT LOMBARD-SHERIDAN LCP 719	90	1	Project	Repetitive Outage Projects	ALBION	Reduce Repeated Outages; Customer-outage-minutes avoided	3,747
3	LVD Repetitive Outages	RPOUT BENTHEIM-140TH AVENUE LCP 662	90	1	Project	Repetitive Outage Projects	SALEM	Reduce Repeated Outages; Customer-outage-minutes avoided	7,455
4	LVD Repetitive Outages	RPOUT LOOMIS-LOOMIS ROAD LCP 657	90	1	Project	Repetitive Outage Projects	OLIVE	Reduce Repeated Outages; Customer-outage-minutes avoided	32,679
5	LVD Repetitive Outages	RPOUT COTTAGE GROVE-HURON LCP 591	90	1	Project	Repetitive Outage Projects	KAWKAWLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	139,679
6	LVD Repetitive Outages	RPOUT BLACKMAN-HURST LCP 490	90	1	Project	Repetitive Outage Projects	PARMA	Reduce Repeated Outages; Customer-outage-minutes avoided	36,443
7	LVD Repetitive Outages	RPOUT MILL GROVE-ALLEGAN HYDRO LCP 831	90	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	7,768
8	LVD Repetitive Outages	RPOUT DUFFIELD-DUFFIELD LCP 696	90	1	Project	Repetitive Outage Projects	LENNON	Reduce Repeated Outages; Customer-outage-minutes avoided	21,415
9	LVD Repetitive Outages	RPOUT ELEVENTH STREET-BASELINE LCP 871	90	1	Project	Repetitive Outage Projects	GUN PLAIN	Reduce Repeated Outages; Customer-outage-minutes avoided	144,568
10	LVD Repetitive Outages	RPOUT CENTREVILLE-COVERED BRIDGE LCP 333	90	1	Project	Repetitive Outage Projects	CENTREVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	21,613
11	LVD Repetitive Outages	RPOUT SARANAC-SARANAC LCP 709	90	1	Project	Repetitive Outage Projects	SARANAC	Reduce Repeated Outages; Customer-outage-minutes avoided	9,720
12	LVD Repetitive Outages	RPOUT SARANAC-RIVERSIDE LCP 735	90	1	Project	Repetitive Outage Projects	SARANAC	Reduce Repeated Outages; Customer-outage-minutes avoided	30,127
13	LVD Repetitive Outages	RPOUT HOMER-HOMER LCP 404	90	1	Project	Repetitive Outage Projects	HOMER	Reduce Repeated Outages; Customer-outage-minutes avoided	3,524
14	LVD Repetitive Outages	RPOUT HULL STREET-CRANBERRY LCP 462	90	1	Project	Repetitive Outage Projects	SPARTA	Reduce Repeated Outages; Customer-outage-minutes avoided	75,217
15	LVD Repetitive Outages	RPOUT BATTEESE-PLEASANT LAKE LCP 8	90	1	Project	Repetitive Outage Projects	LESLIE	Reduce Repeated Outages; Customer-outage-minutes avoided	68,009
16	LVD Repetitive Outages	RPOUT WAMPLERS-STAGECOACH LCP 287	90	1	Project	Repetitive Outage Projects	MANCHESTER	Reduce Repeated Outages; Customer-outage-minutes avoided	50,122
17	LVD Repetitive Outages	RPOUT GODFREY-LOWELL LCP 480	90	1	Project	Repetitive Outage Projects	KEENE	Reduce Repeated Outages; Customer-outage-minutes avoided	17,560
18	LVD Repetitive Outages	RPOUT NORTH ADAMS-NORTH ADAMS LCP 317	90	1	Project	Repetitive Outage Projects	NORTH ADAMS	Reduce Repeated Outages; Customer-outage-minutes avoided	126,954
19	LVD Repetitive Outages	RPOUT LATIMER-CARR LAKE LCP 630	90	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	17,592
20	LVD Repetitive Outages	RPOUT OHMAN ROAD-SEARS LCP 662	90	1	Project	Repetitive Outage Projects	EVART	Reduce Repeated Outages; Customer-outage-minutes avoided	12,036
21	LVD Repetitive Outages	RPOUT LEVEL PARK-COLLIER LCP 261	90	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	95,546
22	LVD Repetitive Outages	RPOUT NEELEY-HOOPER LCP 304	90	1	Project	Repetitive Outage Projects	PRAIRIEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	7,947
23	LVD Repetitive Outages	RPOUT LESLIE-BUSINESS LCP 113	90	1	Project	Repetitive Outage Projects	LESLIE	Reduce Repeated Outages; Customer-outage-minutes avoided	57,784
24	LVD Repetitive Outages	RPOUT MORLEY-HOLLAND LCP 105	90	1	Project	Repetitive Outage Projects	BRIDGEPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	48,047
25	LVD Repetitive Outages	RPOUT GREGORY-GREGORY LCP 678	90	1	Project	Repetitive Outage Projects	UNADILLA	Reduce Repeated Outages; Customer-outage-minutes avoided	18,832
26	LVD Repetitive Outages	RPOUT SQUIRES-ALLEN LCP 10	90	1	Project	Repetitive Outage Projects	ALLEN	Reduce Repeated Outages; Customer-outage-minutes avoided	29,460
27	LVD Repetitive Outages	RPOUT MCKEIGHAN-BRADY ROAD LCP 662	90	1	Project	Repetitive Outage Projects	CHESANING	Reduce Repeated Outages; Customer-outage-minutes avoided	25,327
28	LVD Repetitive Outages	RPOUT JOHNSON-CEDAR LCP 566	90	1	Project	Repetitive Outage Projects	ROBINSON	Reduce Repeated Outages; Customer-outage-minutes avoided	59,498
29	LVD Repetitive Outages	RPOUT ARTHUR-ARTHUR LCP 304	90	1	Project	Repetitive Outage Projects	COOPERSVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	40,171
30	LVD Repetitive Outages	RPOUT MANNSIDING-CEDAR LCP 911	90	1	Project	Repetitive Outage Projects	REDDING	Reduce Repeated Outages; Customer-outage-minutes avoided	31,596
31	LVD Repetitive Outages	RPOUT SPICEBUSH-LACOTA LCP 734	90	1	Project	Repetitive Outage Projects	S HAVEN	Reduce Repeated Outages; Customer-outage-minutes avoided	52,266
32	LVD Repetitive Outages	RPOUT GRANT-GRANT LCP 620	90	1	Project	Repetitive Outage Projects	GRANT	Reduce Repeated Outages; Customer-outage-minutes avoided	35,165
33	LVD Repetitive Outages	RPOUT LETTS ROAD-WALKER LCP 222	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	42,123
34	LVD Repetitive Outages	RPOUT TEKONSHA-TEKONSHA LCP 158	90	1	Project	Repetitive Outage Projects	TEKONSHA	Reduce Repeated Outages; Customer-outage-minutes avoided	94,916
35	LVD Repetitive Outages	RPOUT MILL GROVE-DUMONT LCP 667	90	1	Project	Repetitive Outage Projects	WATSON	Reduce Repeated Outages; Customer-outage-minutes avoided	68,518
36	LVD Repetitive Outages	RPOUT MARTIN-SHELBYVILLE LCP 212	90	1	Project	Repetitive Outage Projects	MARTIN	Reduce Repeated Outages; Customer-outage-minutes avoided	42,361
37	LVD Repetitive Outages	RPOUT KENT CITY-CASNOVIA LCP 774	90	1	Project	Repetitive Outage Projects	CASNOVIA	Reduce Repeated Outages; Customer-outage-minutes avoided	14,542
38	LVD Repetitive Outages	RPOUT HASTINGS-VIKING LCP 133	90	1	Project	Repetitive Outage Projects	HASTINGS	Reduce Repeated Outages; Customer-outage-minutes avoided	67,216
39	LVD Repetitive Outages	RPOUT CENTRAL LAKE-ELLSWORTH LCP 742	90	1	Project	Repetitive Outage Projects	ELLSWORTH	Reduce Repeated Outages; Customer-outage-minutes avoided	43,028
40	LVD Repetitive Outages	RPOUT PEACOCK-STOLL ROAD LCP 441	90	2	Project	Repetitive Outage Projects	WOODHULL	Reduce Repeated Outages; Customer-outage-minutes avoided	14,939
41	LVD Repetitive Outages	RPOUT TALLMAN-WACOUSTA LCP 250	90	3	Project	Repetitive Outage Projects	WESTPHALIA	Reduce Repeated Outages; Customer-outage-minutes avoided	45,469
42	LVD Repetitive Outages	RPOUT ALDER CREEK-LEE LAKE LCP 495	90	4	Project	Repetitive Outage Projects	UNION CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	69,417
43	LVD Repetitive Outages	RPOUT M.A.E.-ALBAIN ROAD LCP 126	90	5	Project	Repetitive Outage Projects	MONROE	Reduce Repeated Outages; Customer-outage-minutes avoided	22,087
44	LVD Repetitive Outages	RPOUT PORTSMOUTH-INDIANTOWN LCP 319	90	6	Project	Repetitive Outage Projects	REESE	Reduce Repeated Outages; Customer-outage-minutes avoided	89,545
45	LVD Repetitive Outages	RPOUT SILVER LAKE-SILVER PINES LCP 446	90	7	Project	Repetitive Outage Projects	GARFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	62,574
46	LVD Repetitive Outages	RPOUT BALCOM-BANKERS LCP 769	17	8	Project	Repetitive Outage Projects	HILLSDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	65,494
47		**LVD Repetitive Outages Subtotal**	**4,067**						
48		**LVD Repetitive Outages Total**	**21,089**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

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Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Resiliency								
2		BACKUS	6,768	1	Project	Resiliency - Fractionalization	Roscommon Co.	Customer outage minutes avoided	217,331
3		GREENWOOD	1,143	1	Project	Resiliency - Fractionalization	Ogemaw Co.	Customer outage minutes avoided	361,337
4		MOBILE 27	784	1	Project	Resiliency - Fractionalization	Statewide	Customer outage minutes avoided	-
5		WHITTEMORE	3,569	1	Project	Resiliency - Fractionalization (IIJA Federal Grant Program)	Iosco Co.	Customer outage minutes avoided	107,599
6		ROSE CITY	156	1	Project	Resiliency - Fractionalization	Ogemaw Co.	Customer outage minutes avoided	4,336
7		OWOSSO	75	1	Project	Resiliency - Fractionalization	Shiawassee Co.	Customer outage minutes avoided	203,520
8		LINCOLN	2,191	1	Project	Resiliency - Fractionalization	Alcona Co.	Customer outage minutes avoided	96,240
9		BROUGHWELL	500	1	Project	Resiliency - Fractionalization	Jackson Co.	Customer outage minutes avoided	145,200
10		EAGLE	640	0	Projects	Resiliency - Fractionalization	Ottawa Co.	Customer-outage-minutes avoided	-
11		TAWAS/TAWAS/482	530	0.8	miles	Overhead to Underground - Carryover From Pilot	Alabaster Twp, Iosco Co.	Customer-outage-minutes avoided	58,181
12		SQUIRE HILL/EDGEWATER/775	720	0.6	miles	Overhead to Underground - Vulnerable Community	Flint Twp, Genesee Co.	Customer-outage-minutes avoided	20,388
13		EGLE GRANT - Undergrounding Services - Grand Rapids	1,232	2	Projects	Undergrounding of Services and Secondary Improvements in DACs	Grand Rapids	Improved MIEJ Reliability; Customers	65
14		EGLE GRANT - Undergrounding Services - Flint	664	1	Project	Undergrounding of Services and Secondary Improvements in DACs	Flint	Improved MIEJ Reliability; Customers	20
15		EGLE GRANT - Undergrounding Services - Kalamazoo	2,222	4	Projects	Undergrounding of Services and Secondary Improvements in DACs	Kalamazoo	Improved MIEJ Reliability; Customers	108
16		**Resiliency Total**	**21,194**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE ALGER_FOREST LAKE LCP 098	12	1	Project	Overloaded Equipment Upgrades	DEEP RIVER TOWNSHIP	Overload Failure Reduction; Customers	43
2	LVD Lines Capacity	DARE ALGER_SKIDWAY LCP 981	13	1	Project	Overloaded Equipment Upgrades	CHURCHILL TOWNSHIP	Overload Failure Reduction; Customers	103
3	LVD Lines Capacity	DARE ASHMAN CIRCLE SUGNET LCP 402	2	1	Project	Overloaded Equipment Upgrades	MIDLAND	Overload Failure Reduction; Customers	17
4	LVD Lines Capacity	DARE BACKUS-SPRINGBROOK LCP 240	30	1	Project	Overloaded Equipment Upgrades	MARKEY TOWNSHIP	Overload Failure Reduction; Customers	445
5	LVD Lines Capacity	DARE BACKUS-SPRINGBROOK LCP 241	2	1	Project	Overloaded Equipment Upgrades	MARKEY TOWNSHIP	Overload Failure Reduction; Customers	444
6	LVD Lines Capacity	DARE BAY ROAD_DAVIS ROAD LCP 811 ISO	6	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	36
7	LVD Lines Capacity	DARE BRECKENRIDGE_WHEELER LCP 691	59	1	Project	Overloaded Equipment Upgrades	WHEELER TOWNSHIP	Overload Failure Reduction; Customers	314
8	LVD Lines Capacity	DARE BUTTERFIELD LINDEN LCP 704	10	1	Project	Overloaded Equipment Upgrades	BROOKS TOWNSHIP	Overload Failure Reduction; Customers	60
9	LVD Lines Capacity	DARE BUTTERFIELD LINDEN LCP 723	508	1	Project	Overloaded Equipment Upgrades	BROOKS TOWNSHIP	Overload Failure Reduction; Customers	132
10	LVD Lines Capacity	DARE BUTTERFIELD M-82 LCP 536	22	1	Project	Overloaded Equipment Upgrades	BROOKS TOWNSHIP	Overload Failure Reduction; Customers	67
11	LVD Lines Capacity	DARE BUTTERFIELD M-82 LCP 641	11	1	Project	Overloaded Equipment Upgrades	BROOKS TOWNSHIP	Overload Failure Reduction; Customers	118
12	LVD Lines Capacity	DARE CALEDONIA 92ND ST LCP 506	18	1	Project	Overloaded Equipment Upgrades	CALEDONIA	Overload Failure Reduction; Customers	48
13	LVD Lines Capacity	DARE CAMDEN_MONTGOMERY LCP 283	14	1	Project	Overloaded Equipment Upgrades	CAMDEN TOWNSHIP	Overload Failure Reduction; Customers	105
14	LVD Lines Capacity	DARE Camelot Lake Coleman LCP 360	20	1	Project	Overloaded Equipment Upgrades	GREENDALE TOWNSHIP	Overload Failure Reduction; Customers	171
15	LVD Lines Capacity	Dare Casino/Leaton LCP 888	49	1	Project	Overloaded Equipment Upgrades	CHIPPEWA TOWNSHIP	Overload Failure Reduction; Customers	881
16	LVD Lines Capacity	DARE18 EIGHT PT WHT BIRCH LCP 531	419	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	633
17	LVD Lines Capacity	DARE18 EIGHT PT WHT BIRCH LCP 531 PT 2	285	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	633
18	LVD Lines Capacity	DARE18 EIGHT PT WHT BIRCH LCP 531 PT 3	72	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	633
19	LVD Lines Capacity	DARE18 EIGHT PT WHT BIRCH LCP 531 UG	12	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	633
20	LVD Lines Capacity	DARE Crystal_Crystal Rd LCP 483_494_533	36	1	Project	Overloaded Equipment Upgrades	CRYSTAL TOWNSHIP	Overload Failure Reduction; Customers	556
21	LVD Lines Capacity	DARE CUTLERVILLE_SPARTAN LCP 775 rm reg	23	1	Project	Overloaded Equipment Upgrades	BYRON TOWNSHIP	Overload Failure Reduction; Customers	375
22	LVD Lines Capacity	DARE DEXTER TRAIL MILNER LCP 115	16	1	Project	Overloaded Equipment Upgrades	STOCKBRIDGE TOWNSHIP	Overload Failure Reduction; Customers	255
23	LVD Lines Capacity	DARE DOBSON ROAD_HALF MOON LCP 375	15	1	Project	Overloaded Equipment Upgrades	MOSCOW TOWNSHIP	Overload Failure Reduction; Customers	26
24	LVD Lines Capacity	DARE EDMORE/SIX LAKES LCP 372 PT1	200	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	181
25	LVD Lines Capacity	DARE EDMORE/SIX LAKES LCP 372 PT2	340	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	181
26	LVD Lines Capacity	DARE EDMORE/SIX LAKES LCP 372 PT3	218	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	181
27	LVD Lines Capacity	DARE EDMORE/SIX LAKES LCP 372 PT4	36	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	181
28	LVD Lines Capacity	DARE Ft Custer - Harmonia LCP 307	163	1	Project	Overloaded Equipment Upgrades	BATTLE CREEK	Overload Failure Reduction; Customers	496
29	LVD Lines Capacity	DARE GRANT MASON DRIVE LCP 235	213	1	Project	Overloaded Equipment Upgrades	GRANT	Overload Failure Reduction; Customers	186
30	LVD Lines Capacity	DARE GREENWOOD_INDIAN LAKE LCP 746	66	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	575
31	LVD Lines Capacity	DARE GREENWOOD_INDIAN LAKE LCP 765	54	1	Project	Overloaded Equipment Upgrades	ALGER	Overload Failure Reduction; Customers	156
32	LVD Lines Capacity	DARE GROVER/TRIANGLE LCP 441	78	1	Project	Overloaded Equipment Upgrades	EMERSON TOWNSHIP	Overload Failure Reduction; Customers	311
33	LVD Lines Capacity	DARE GUN LAKE_ENGLAND LCP 314	4	1	Project	Overloaded Equipment Upgrades	YANKEE SPRINGS TOWNSH	Overload Failure Reduction; Customers	1093
34	LVD Lines Capacity	DARE GUN LAKE_ENGLAND LCP 379	29	1	Project	Overloaded Equipment Upgrades	YANKEE SPRINGS TOWNSH	Overload Failure Reduction; Customers	58
35	LVD Lines Capacity	DARE HART DISTRIBUTION LCP 451	20	1	Project	Overloaded Equipment Upgrades	HART	Overload Failure Reduction; Customers	22
36	LVD Lines Capacity	DARE HART DISTRIBUTION LCP 451 - UG	7	1	Project	Overloaded Equipment Upgrades	HART	Overload Failure Reduction; Customers	22
37	LVD Lines Capacity	DARE Harvard Lake_Courtland LCP 411	26	1	Project	Overloaded Equipment Upgrades	COURTLAND TOWNSHIP	Overload Failure Reduction; Customers	70
38	LVD Lines Capacity	DARE HESPERIA RURAL LCP 325 PART 1	267	1	Project	Overloaded Equipment Upgrades	DENVER TOWNSHIP	Overload Failure Reduction; Customers	126
39	LVD Lines Capacity	DARE HESPERIA RURAL LCP 325 PART 2	158	1	Project	Overloaded Equipment Upgrades	HESPERIA	Overload Failure Reduction; Customers	126
40	LVD Lines Capacity	DARE HESPERIA RURAL LCP 325 PART 3	367	1	Project	Overloaded Equipment Upgrades	HESPERIA	Overload Failure Reduction; Customers	126
41	LVD Lines Capacity	DARE HESPERIA RURAL LCP 325 PART 4	350	1	Project	Overloaded Equipment Upgrades	HESPERIA	Overload Failure Reduction; Customers	126
42	LVD Lines Capacity	DARE HESPERIA RURAL LCP 325 PART 5	350	2	Project	Overloaded Equipment Upgrades	HESPERIA	Overload Failure Reduction; Customers	127
43	LVD Lines Capacity	DARE HESPERIA RURAL LCP 325 PART 6	333	3	Project	Overloaded Equipment Upgrades	HESPERIA	Overload Failure Reduction; Customers	128
42	LVD Lines Capacity	DARE18 HUNT ROAD_HUNT ROAD LCP 0408	510	1	Project	Overloaded Equipment Upgrades	ADRIAN TOWNSHIP	Overload Failure Reduction; Customers	147
43	LVD Lines Capacity	DARE ITHACA/FAIR GROUNDS LCP 313	9	1	Project	Overloaded Equipment Upgrades	EMERSON TOWNSHIP	Overload Failure Reduction; Customers	45
44	LVD Lines Capacity	DARE JASPER REDSTONE LCP 852	35	1	Project	Overloaded Equipment Upgrades	COE TOWNSHIP	Overload Failure Reduction; Customers	130
45	LVD Lines Capacity	DARE KALAMO HWY ADD PHASE	119	1	Project	Overloaded Equipment Upgrades	CHARLOTTE	Overload Failure Reduction; Customers	319
46	LVD Lines Capacity	DARE KAWKAWLIN-RUSSELL LCP 433	11	1	Project	Overloaded Equipment Upgrades	KAWKAWLIN	Overload Failure Reduction; Customers	322
47	LVD Lines Capacity	DARE KIPP HULL LCP5297 250 I	20	1	Project	Overloaded Equipment Upgrades	MASON	Overload Failure Reduction; Customers	108
48	LVD Lines Capacity	DARE Kolassa_Kosmerick LCP 383	16	1	Project	Overloaded Equipment Upgrades	NOBLE TOWNSHIP	Overload Failure Reduction; Customers	23
49	LVD Lines Capacity	DARE LAWRENCE CHRISTIE LAKE	38	1	Project	Overloaded Equipment Upgrades	LAWRENCE TOWNSHIP	Overload Failure Reduction; Customers	415
50	LVD Lines Capacity	DARE Levely Sturgeon LCP 295	20	1	Project	Overloaded Equipment Upgrades	EDENVILLE TOWNSHIP	Overload Failure Reduction; Customers	32
		LVD Lines Capacity Subtotal	**5,711**						

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($000)

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Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE LKLeANN-BUNDYHILL-608ISO-OVERLOAD	13	1	Project	Overloaded Equipment Upgrades	SOMERSET TOWNSHIP	Overload Failure Reduction; Customers	91
2	LVD Lines Capacity	DARE Loomis-Loomis LCP 654	20	1	Project	Overloaded Equipment Upgrades	OLIVE TOWNSHIP	Overload Failure Reduction; Customers	185
3	LVD Lines Capacity	DARE Marker Lake_Kyser Rd LCP 590	325	1	Project	Overloaded Equipment Upgrades	BOSTON TOWNSHIP	Overload Failure Reduction; Customers	342
4	LVD Lines Capacity	DARE MCBAIN-LAKE CITY LCP 758	27	1	Project	Overloaded Equipment Upgrades	REEDER TOWNSHIP	Overload Failure Reduction; Customers	137
5	LVD Lines Capacity	DARE MIDDLETON_NEWARK LCP 701	6	1	Project	Overloaded Equipment Upgrades	FULTON TOWNSHIP	Overload Failure Reduction; Customers	58
6	LVD Lines Capacity	DARE MIDDLETON_NEWARK LCP 826	51	1	Project	Overloaded Equipment Upgrades	FULTON TOWNSHIP	Overload Failure Reduction; Customers	82
7	LVD Lines Capacity	DARE MILL GROVE ALLEGAN HYDRO LCP 923	18	1	Project	Overloaded Equipment Upgrades	VALLEY TOWNSHIP	Overload Failure Reduction; Customers	57
8	LVD Lines Capacity	DARE NASHVILLE VERMONTVILLE	35	1	Project	Overloaded Equipment Upgrades	VERMONTVILLE	Overload Failure Reduction; Customers	375
9	LVD Lines Capacity	DARE Olivet College 415	60	1	Project	Overloaded Equipment Upgrades	WALTON TOWNSHIP	Overload Failure Reduction; Customers	500
10	LVD Lines Capacity	DARE OwossoGould M-52 PH I OliverSt	551	1	Project	Overloaded Equipment Upgrades	OWOSSO	Overload Failure Reduction; Customers	2100
11	LVD Lines Capacity	DARE PARAMOUNT/NORTHLAND FARMS LCP-792	384	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	90
12	LVD Lines Capacity	DARE Peninsula/Mapleton LCP 7518	78	1	Project	Overloaded Equipment Upgrades	TRAVERSE CITY	Overload Failure Reduction; Customers	1325
13	LVD Lines Capacity	DARE PICKEREL-INDIAN LAKE	16	1	Project	Overloaded Equipment Upgrades	PAVILION TOWNSHIP	Overload Failure Reduction; Customers	815
14	LVD Lines Capacity	DARE PLAINWELL_HEIGHTS LCP 852	10	1	Project	Overloaded Equipment Upgrades	PLAINWELL	Overload Failure Reduction; Customers	1131
15	LVD Lines Capacity	DARE PRESCOTT_LOGAN LCP 575	169	1	Project	Overloaded Equipment Upgrades	RENO TOWNSHIP	Overload Failure Reduction; Customers	124
16	LVD Lines Capacity	DARE PRESCOTT_MAPLE RIDGE LCP 332	114	1	Project	Overloaded Equipment Upgrades	MASON TOWNSHIP	Overload Failure Reduction; Customers	166
17	LVD Lines Capacity	DARE RIVERDALE/SUMNER LCP 080	93	1	Project	Overloaded Equipment Upgrades	SUMNER TOWNSHIP	Overload Failure Reduction; Customers	547
18	LVD Lines Capacity	DARE RIVERDALE_RIVERDALE 008	41	1	Project	Overloaded Equipment Upgrades	SEVILLE TOWNSHIP	Overload Failure Reduction; Customers	195
19	LVD Lines Capacity	DARE Saranac_Saranac LCP 740	39	1	Project	Overloaded Equipment Upgrades	BOSTON TOWNSHIP	Overload Failure Reduction; Customers	135
20	LVD Lines Capacity	DARE SAUGATUCK_DOUGLAS LCP 085	5	1	Project	Overloaded Equipment Upgrades	DOUGLAS TOWNSHIP	Overload Failure Reduction; Customers	75
21	LVD Lines Capacity	DARE SAUGATUCK_SILVER LAKE LCP 875	5	1	Project	Overloaded Equipment Upgrades	SAUGATUCK TOWNSHIP	Overload Failure Reduction; Customers	64
22	LVD Lines Capacity	DARE SHEPHERD_FOREST HILL LCP 181	29	1	Project	Overloaded Equipment Upgrades	PINE RIVER TOWNSHIP	Overload Failure Reduction; Customers	158
23	LVD Lines Capacity	Dare Silver Lake Silver Pines LCP 446	131	1	Project	Overloaded Equipment Upgrades	TRAVERSE CITY	Overload Failure Reduction; Customers	481
24	LVD Lines Capacity	DARE SIMMONS_DAM RD LCP 259	33	1	Project	Overloaded Equipment Upgrades	WEST BRANCH	Overload Failure Reduction; Customers	172
25	LVD Lines Capacity	DARE SIMMONS_DAM RD LCP 616	33	1	Project	Overloaded Equipment Upgrades	WEST BRANCH	Overload Failure Reduction; Customers	124
26	LVD Lines Capacity	DARE SMALLWOOD DAM_WOODEN SHOE LCP 555	38	1	Project	Overloaded Equipment Upgrades	HAY TOWNSHIP	Overload Failure Reduction; Customers	527
27	LVD Lines Capacity	DARE SMITH CREEK_SKIPARK LCP 170	33	1	Project	Overloaded Equipment Upgrades	WEST BRANCH	Overload Failure Reduction; Customers	112
28	LVD Lines Capacity	DARE SPICEBUSH_LACOTA ISO 102	33	1	Project	Overloaded Equipment Upgrades	CASCO TOWNSHIP	Overload Failure Reduction; Customers	31
29	LVD Lines Capacity	DARE SPICEBUSH_LACOTA ISO 803	20	1	Project	Overloaded Equipment Upgrades	CASCO TOWNSHIP	Overload Failure Reduction; Customers	96
30	LVD Lines Capacity	DARE STONEY CORNERS-DAIRY LCP 343	720	1	Project	Overloaded Equipment Upgrades	RICHLAND TOWNSHIP	Overload Failure Reduction; Customers	60
31	LVD Lines Capacity	DARE STONEY CORNERS-STONE LDG LCP 5061	38	1	Project	Overloaded Equipment Upgrades	CADILLAC	Overload Failure Reduction; Customers	170
32	LVD Lines Capacity	DARE Sturgeon Perrine LCP 261	12	1	Project	Overloaded Equipment Upgrades	MIDLAND	Overload Failure Reduction; Customers	55
33	LVD Lines Capacity	DARE TEKONSHA_TEKONSHA LCP 221	2	1	Project	Overloaded Equipment Upgrades	CLARENDON TOWNSHIP	Overload Failure Reduction; Customers	60
34	LVD Lines Capacity	DARE UPTON MARKETPLACE LCP328-300A	10	1	Project	Overloaded Equipment Upgrades	GRAND LEDGE	Overload Failure Reduction; Customers	1081
35	LVD Lines Capacity	DARE WHITTEMORE_SAND LAKE LCP 007	60	1	Project	Overloaded Equipment Upgrades	GRANT TOWNSHIP	Overload Failure Reduction; Customers	387
36	LVD Lines Capacity	DARE WHITTEMORE_SAND LAKE LCP 603	42	1	Project	Overloaded Equipment Upgrades	GRANT TOWNSHIP	Overload Failure Reduction; Customers	504
37	LVD Lines Capacity	DARE WHITTEMORE_SAND LAKE LCP 605	84	1	Project	Overloaded Equipment Upgrades	GRANT TOWNSHIP	Overload Failure Reduction; Customers	312
38	LVD Lines Capacity	DARE WOODWARD-PLEASANT LK LCP 982	283	1	Project	Overloaded Equipment Upgrades	HARING TOWNSHIP	Overload Failure Reduction; Customers	207
39	LVD Lines Capacity	DARE15 CRANBROOK 11 MILE PT. 1	278	1	Project	Overloaded Equipment Upgrades	EMMETT TOWNSHIP	Overload Failure Reduction; Customers	310
40	LVD Lines Capacity	DARE15 CRANBROOK 11 MILE PT. 2	236	1	Project	Overloaded Equipment Upgrades	EMMETT TOWNSHIP	Overload Failure Reduction; Customers	310
41	LVD Lines Capacity	DARE15 CRANBROOK 11 MILE PT. 3	219	1	Project	Overloaded Equipment Upgrades	EMMETT TOWNSHIP	Overload Failure Reduction; Customers	310
42	LVD Lines Capacity	DARE15 CRANBROOK 11 MILE PT. 4	187	1	Project	Overloaded Equipment Upgrades	EMMETT TOWNSHIP	Overload Failure Reduction; Customers	310
43	LVD Lines Capacity	DARE15 CRANBROOK 17 OHS	36	1	Project	Overloaded Equipment Upgrades	BATTLE CREEK	Overload Failure Reduction; Customers	17
44	LVD Lines Capacity	DARE16 HARLEM_QUINCY ST LCP 475 #2	182	1	Project	Overloaded Equipment Upgrades	HOLLAND	Overload Failure Reduction; Customers	346
45	LVD Lines Capacity	DARE17 15 MILE ROAD/15 MILE ROAD 605 1	623	1	Project	Overloaded Equipment Upgrades	MARENGO TOWNSHIP	Overload Failure Reduction; Customers	174
46	LVD Lines Capacity	DARE17 CAMELOT LAKE/LOOMIS LCP 467	18	1	Project	Overloaded Equipment Upgrades	CHIPPEWA TOWNSHIP	Overload Failure Reduction; Customers	57
47	LVD Lines Capacity	DARE17 FENNVILLE/COMMERCIAL***	725	1	Project	Overloaded Equipment Upgrades	CLYDE TOWNSHIP	Overload Failure Reduction; Customers	784
48	LVD Lines Capacity	DARE17 MAGNUS EAGL CRNR LCP 823 PH3	148	1	Project	Overloaded Equipment Upgrades	CLARE	Overload Failure Reduction; Customers	45
49		**LVD Lines Capacity Subtotal**	**6,312**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE17 MT FOREST_MT FOREST LCP 616	29	1	Project	Overloaded Equipment Upgrades	BENTLEY	Overload Failure Reduction; Customers	85
2	LVD Lines Capacity	DARE17 MT PLEASANT/BROADWAY FUSES	14	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	596
3	LVD Lines Capacity	DARE17 SURREY/SURREY LCP 711	16	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	182
4	LVD Lines Capacity	DARE17HAGADORN-BEAUMONT	149	1	Project	Overloaded Equipment Upgrades	EAST LANSING	Overload Failure Reduction; Customers	210
5	LVD Lines Capacity	DARE18 BRECKENRIDGE/VILLAGE LCP 603	2	1	Project	Overloaded Equipment Upgrades	BRECKENRIDGE	Overload Failure Reduction; Customers	128
6	LVD Lines Capacity	DARE18 DEER LK/CRANBERRY LCP 268	576	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	318
7	LVD Lines Capacity	DARE18NAPOLEON/WOLF LK-CADY RD	368	1	Project	Overloaded Equipment Upgrades	NAPOLEON TOWNSHIP	Overload Failure Reduction; Customers	340
8	LVD Lines Capacity	DARE19 BENTHEIM-140TH AVE LCP341-PT 1*	215	1	Project	Overloaded Equipment Upgrades	OVERISEL TOWNSHIP	Overload Failure Reduction; Customers	110
9	LVD Lines Capacity	DARE19 BENTHEIM-140TH AVE LCP341-PT 2*	281	1	Project	Overloaded Equipment Upgrades	OVERISEL TOWNSHIP	Overload Failure Reduction; Customers	110
10	LVD Lines Capacity	DARE19 Clyde Rd_State Rd	44	1	Project	Overloaded Equipment Upgrades	IONIA	Overload Failure Reduction; Customers	345
11	LVD Lines Capacity	DARE19 EIGHT POINT WHITE BIRCH LCP 830 1	270	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	317
12	LVD Lines Capacity	DARE19 EIGHT POINT WHITE BIRCH LCP 830 2	283	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	317
13	LVD Lines Capacity	DARE19 EIGHT POINT WHITE BIRCH LCP 830 3	20	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	317
14	LVD Lines Capacity	DARE19 Hemlock/Hemlock LCP 688	46	1	Project	Overloaded Equipment Upgrades	RICHLAND TOWNSHIP	Overload Failure Reduction; Customers	128
15	LVD Lines Capacity	DARE19 PECK RD ORE-IDA LCP 828	96	1	Project	Overloaded Equipment Upgrades	GREENVILLE	Overload Failure Reduction; Customers	469
16	LVD Lines Capacity	DARE21 DEER LAKE CRANBRY LK LCP 303	20	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	989
17	LVD Lines Capacity	DARE21 EIGHT POINT WHITE BRCH LCP 565	213	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	165
18	LVD Lines Capacity	DARE21 EIGHT POINT WHITE BRCH LCP 565 UG	12	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	165
19	LVD Lines Capacity	DARE21 FIFTEEN MILE 15 MILE LCP 258	16	1	Project	Overloaded Equipment Upgrades	MARENGO TOWNSHIP	Overload Failure Reduction; Customers	48
20	LVD Lines Capacity	DARE21 FIFTEEN MILE A DRIVE LCP 113	8	1	Project	Overloaded Equipment Upgrades	MARSHALL TOWNSHIP	Overload Failure Reduction; Customers	179
21	LVD Lines Capacity	DARE21 INGHAM-GREENWOOD LCP 844-65	5	1	Project	Overloaded Equipment Upgrades	JACKSON	Overload Failure Reduction; Customers	1
22	LVD Lines Capacity	DARE21 Levely_Sturgeon LCP 111	12	1	Project	Overloaded Equipment Upgrades	HOPE TOWNSHIP	Overload Failure Reduction; Customers	128
23	LVD Lines Capacity	DARE21 LOVEJOY Braden LCP 847 ISOLATOR	50	1	Project	Overloaded Equipment Upgrades	DEERFIELD TOWNSHIP	Overload Failure Reduction; Customers	69
24	LVD Lines Capacity	DARE21 Nineteen Mile-Cement LCP 184	15	1	Project	Overloaded Equipment Upgrades	GREEN TOWNSHIP	Overload Failure Reduction; Customers	37
25	LVD Lines Capacity	DARE21-TEKONSHA-WAGNER-LCP 245	17	1	Project	Overloaded Equipment Upgrades	BURLINGTON TOWNSHIP	Overload Failure Reduction; Customers	240
26	LVD Lines Capacity	DARE22 DEER LAKE BALL AVE LCP 413	29	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	150
27	LVD Lines Capacity	Dare22 Parnall Parnall RD LCP 0436	3	1	Project	Overloaded Equipment Upgrades	JACKSON	Overload Failure Reduction; Customers	43
28	LVD Lines Capacity	DARE21 BALCOM-BANKERS-LCP 795	259	1	Project	Overloaded Equipment Upgrades	READING TOWNSHIP	Overload Failure Reduction; Customers	38
29	LVD Lines Capacity	DARE CARY-MOSCOW-242-WOODBROOK	47	1	Project	Overloaded Equipment Upgrades	SOMERSET TOWNSHIP	Overload Failure Reduction; Customers	231
30	LVD Lines Capacity	DARE CHAPIN_MARION LCP 925	7	1	Project	Overloaded Equipment Upgrades	CHAPIN TOWNSHIP	Overload Failure Reduction; Customers	216
31	LVD Lines Capacity	DARE Clear Lake Harvey Road LCP 216	65	1	Project	Overloaded Equipment Upgrades	GRASS LAKE	Overload Failure Reduction; Customers	60
32	LVD Lines Capacity	DARE DIVISION_PIEDMONT LCP 117	85	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	353
33	LVD Lines Capacity	DARE24 GREGORY UNADILLA LCP 765	20	1	Project	Overloaded Equipment Upgrades	UNADILLA TOWNSHIP	Overload Failure Reduction; Customers	98
34	LVD Lines Capacity	DARE13 NAPOLEON/WOLF LK-NAPOLEON RD	704	1	Project	Overloaded Equipment Upgrades	NAPOLEON TOWNSHIP	Overload Failure Reduction; Customers	109
35	LVD Lines Capacity	DARE N MUSKEGON STATE PARK LCP 076	327	1	Project	Overloaded Equipment Upgrades	NORTH MUSKEGON	Overload Failure Reduction; Customers	842
36	LVD Lines Capacity	Dare21 Stockbridge_Morton	20	1	Project	Overloaded Equipment Upgrades	STOCKBRIDGE TOWNSHIP	Overload Failure Reduction; Customers	125
37	LVD Lines Capacity	DARE RIX RD FAIRLANE LCP 128	423	1	Project	Overloaded Equipment Upgrades	OSHTEMO TOWNSHIP	Overload Failure Reduction; Customers	565
38	LVD Lines Capacity	DARE17 COTTAGE GROVE/PREVO LCP 871 - PT1	766	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	379
39	LVD Lines Capacity	DARE21 MIDDLETON/MIDDLETON LCP 945	281	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	50
40	LVD Lines Capacity	DARE21 MANNSIDING CEDAR LCP 231	8	1	Project	Overloaded Equipment Upgrades	LAKE GEORGE	Overload Failure Reduction; Customers	287
41	LVD Lines Capacity	DARE COLON_PALMER LCP 722	34	1	Project	Overloaded Equipment Upgrades	COLON TOWNSHIP	Overload Failure Reduction; Customers	318
42	LVD Lines Capacity	DARE GERRISH-GOLF CLUB LCP 956	148	1	Project	Overloaded Equipment Upgrades	BEAVER CREEK TOWNSHIP	Overload Failure Reduction; Customers	225
43	LVD Lines Capacity	DARE GERRISH-GOLF CLUB LCP 956 PT 2	333	1	Project	Overloaded Equipment Upgrades	BEAVER CREEK TOWNSHIP	Overload Failure Reduction; Customers	225
44	LVD Lines Capacity	DARE SPICEBUSH_LACOTA ISO 106	33	1	Project	Overloaded Equipment Upgrades	LEE TOWNSHIP	Overload Failure Reduction; Customers	38
45	LVD Lines Capacity	DARE SPICEBUSH-LESTER LAKE ISO 446	36	1	Project	Overloaded Equipment Upgrades	GRAND JUNCTION	Overload Failure Reduction; Customers	199
46	LVD Lines Capacity	DARE OBERLIN_MERIDITH LCP 690	75	1	Project	Overloaded Equipment Upgrades	SHERMAN TOWNSHIP	Overload Failure Reduction; Customers	382
47	LVD Lines Capacity	DARE17 OBERLIN/BENMARK LCP 327 1/2	392	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	183
48	LVD Lines Capacity	DARE22 OBERLIN PRATT LAKE LCP 398	103	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	329
49	LVD Lines Capacity	DARE22 OBERLIN PRATT LAKE LCP 408	536	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	614
50	LVD Lines Capacity	DARE PARAMOUNT/NORTHLAND FARMS LCP-744	257	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	143
51	LVD Lines Capacity	DARE17 PRICE ROAD/PRICE LCP 153	388	1	Project	Overloaded Equipment Upgrades	LINCOLN TOWNSHIP	Overload Failure Reduction; Customers	249
52	LVD Lines Capacity	DARE17 OTSEGO_OTSEGO	71	1	Project	Overloaded Equipment Upgrades	OTSEGO TOWNSHIP	Overload Failure Reduction; Customers	595
53	LVD Lines Capacity	DARE RANGER LAKE_KOKOSING LCP 591	24	1	Project	Overloaded Equipment Upgrades	HALE	Overload Failure Reduction; Customers	241
54	LVD Lines Capacity	DARE RANGER LAKE_LUPTON LCP 522	52	1	Project	Overloaded Equipment Upgrades	LUPTON	Overload Failure Reduction; Customers	284
55	LVD Lines Capacity	DARE RATIGAN_GREELEY LCP 353	36	1	Project	Overloaded Equipment Upgrades	GRATTAN TOWNSHIP	Overload Failure Reduction; Customers	70
56	LVD Lines Capacity	DARE PORTSMOUTH/BLUMFIELD LCP 255	401	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	386
57	LVD Lines Capacity	DARE PORTSMOUTH/INDIANTOWN LCP 133	385	1	Project	Overloaded Equipment Upgrades	MUNGER	Overload Failure Reduction; Customers	315
58	LVD Lines Capacity	DARE Saranac_Saranac LCP 882	218	1	Project	Overloaded Equipment Upgrades	BOSTON TOWNSHIP	Overload Failure Reduction; Customers	149
59	LVD Lines Capacity	DARE18 PEACH RIDGE/BALLARD OHLN CONV PT2	457	1	Project	Sub Capacity-associated Line Work	SPARTA	Overload Failure Reduction; Customers	380
60	LVD Lines Capacity	DARE18 PEACH RIDGE/BALLARD UGLN CONV PT2	24	1	Project	Sub Capacity-associated Line Work	SPARTA	Overload Failure Reduction; Customers	380
61	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT2 1OF2	831	1	Project	Sub Capacity-associated Line Work	CONKLIN	Overload Failure Reduction; Customers	153
62	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT2 2OF2	704	1	Project	Sub Capacity-associated Line Work	CHESTER TOWNSHIP	Overload Failure Reduction; Customers	153
63	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT4 1OF2	428	1	Project	Sub Capacity-associated Line Work	CONKLIN	Overload Failure Reduction; Customers	410
64	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT4 2OF2	288	1	Project	Sub Capacity-associated Line Work	SPARTA TOWNSHIP	Overload Failure Reduction; Customers	410
65	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT4 UGL	67	1	Project	Sub Capacity-associated Line Work	SPARTA TOWNSHIP	Overload Failure Reduction; Customers	410
66	LVD Lines Capacity	DARE21 TAMARACK-LAKEVIEW CONV PH 2.1 S 1	237	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	538
67	LVD Lines Capacity	DARE21 TAMARACK-LAKEVIEW CONV PH 2.1 S 2	405	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	538
68	LVD Lines Capacity	DARE21 TAMARACK-LAKEVIEW CONV PH 2.1 S 3	323	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	538
69	LVD Lines Capacity	DARE21 TAMARACK-LAKEVIEW CONV PH 2.1 S 4	243	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	538
70	LVD Lines Capacity	DARE Palo Substation LVD Rebuild	3208	1	Project	Sub Capacity-associated Line Work	RONALD TOWNSHIP	Overload Failure Reduction; Customers	934
71		**LVD Lines Capacity Subtotal**	**16,528**						
72		**LVD Lines Capacity Total**	**28,551**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	CURRIE PKWY	1	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
2	LVD New Business Capacity	CURRIE PKWY	5	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
3	LVD New Business Capacity	CONRAD INDUSTRIAL DR CLU	16	1	Project	New Business Capacity Request	LUDINGTON	Increase capacity to meet customer demand
4	LVD New Business Capacity	CONRAD INDUSTRIAL DR UPU	3	1	Project	New Business Capacity Request	LUDINGTON	Increase capacity to meet customer demand
5	LVD New Business Capacity	W Green St Hastings ECNC CLO	5	1	Project	New Business Capacity Request	HASTINGS	Increase capacity to meet customer demand
6	LVD New Business Capacity	th Wayland ECNC UPU	8	1	Project	New Business Capacity Request	WAYLAND	Increase capacity to meet customer demand
7	LVD New Business Capacity	ROOD ST, IM FL K Wilson/materials	1	1	Project	New Business Capacity Request	LAKE	Increase capacity to meet customer demand
8	LVD New Business Capacity	E RIVER ST LLND -CLO	20	1	Project	New Business Capacity Request	LELAND	Increase capacity to meet customer demand
9	LVD New Business Capacity	WOODEN RD, HNV ECNC CLO	2	1	Project	New Business Capacity Request	HANOVER	Increase capacity to meet customer demand
10	LVD New Business Capacity	E GRAND RIVER ST, LGBG - NLO	3	1	Project	New Business Capacity Request	LAINGSBURG	Increase capacity to meet customer demand
11	LVD New Business Capacity	E WEST RESORT RD, BTLK - ECNC CLO	2	1	Project	New Business Capacity Request	BURT LAKE	Increase capacity to meet customer demand
12	LVD New Business Capacity	N IRISH RD DVSN-ECNC CLO	4	1	Project	New Business Capacity Request	DAVISON	Increase capacity to meet customer demand
13	LVD New Business Capacity	N IRISH RD DVSN-ECNC CLU	7	1	Project	New Business Capacity Request	DAVISON	Increase capacity to meet customer demand
14	LVD New Business Capacity	N IRISH RD DVSN-ECNC UPU	5	1	Project	New Business Capacity Request	DAVISON	Increase capacity to meet customer demand
15	LVD New Business Capacity	N MITCHELL ST EVC,CAD - CLO	41	1	Project	New Business Capacity Request	CADILLAC	Increase capacity to meet customer demand
16	LVD New Business Capacity	N MITCHELL ST EVC,CAD - UPU	22	1	Project	New Business Capacity Request	CADILLAC	Increase capacity to meet customer demand
17	LVD New Business Capacity	Electric Ave, Wayland, ECNC CLU	16	1	Project	New Business Capacity Request	WAYLAND	Increase capacity to meet customer demand
18	LVD New Business Capacity	EASTON RD NLTP ECNC CLO	6	1	Project	New Business Capacity Request	NEW LOTHROP	Increase capacity to meet customer demand
19	LVD New Business Capacity	EASTON RD NLTP ECNC CLU	2	1	Project	New Business Capacity Request	NEW LOTHROP	Increase capacity to meet customer demand
20	LVD New Business Capacity	N ELMS RD CLIO - ECNC CLO	1	1	Project	New Business Capacity Request	CLIO	Increase capacity to meet customer demand
21	LVD New Business Capacity	APPLE DR CLO	15	1	Project	New Business Capacity Request	NUNICA	Increase capacity to meet customer demand
22	LVD New Business Capacity	APPLE DR UPU	4	1	Project	New Business Capacity Request	NUNICA	Increase capacity to meet customer demand
23	LVD New Business Capacity	WEST SHORE DR, HTNL, ECNC CLO	2	1	Project	New Business Capacity Request	HOUGHTON LAKE	Increase capacity to meet customer demand
24	LVD New Business Capacity	POPLAR ST LAKE ECNC CLO	13	1	Project	New Business Capacity Request	LAKE	Increase capacity to meet customer demand
25	LVD New Business Capacity	HEIGHTS RAVENNA RD CLO	2	1	Project	New Business Capacity Request	RAVENNA	Increase capacity to meet customer demand
26	LVD New Business Capacity	E MONROE RD - BRTN - ECNC CLO	3	1	Project	New Business Capacity Request	BRITTON	Increase capacity to meet customer demand
27	LVD New Business Capacity	Lakeview Court CLO	1	1	Project	New Business Capacity Request	BROOKLYN	Increase capacity to meet customer demand
28	LVD New Business Capacity	BLUFF RD TC ECNC CLO	1	1	Project	New Business Capacity Request	TRAVERSE CITY	Increase capacity to meet customer demand
29	LVD New Business Capacity	W HOME AVE FLT ECNC UPO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
30	LVD New Business Capacity	VASSAR DR, KZOO, ECNC CLO	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
31	LVD New Business Capacity	W TH ST FMT ECNC CLO	0	1	Project	New Business Capacity Request	FREMONT	Increase capacity to meet customer demand
32	LVD New Business Capacity	W TH ST FMT ECNC UPO	1	1	Project	New Business Capacity Request	FREMONT	Increase capacity to meet customer demand
33	LVD New Business Capacity	DUNHAM ST SE GR UPO	1	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
34	LVD New Business Capacity	LINCOLN LAKE AVE, GOWEN	10	1	Project	New Business Capacity Request	GOWEN	Increase capacity to meet customer demand
35	LVD New Business Capacity	LINCOLN LAKE AVE, GOWEN	5	1	Project	New Business Capacity Request	GOWEN	Increase capacity to meet customer demand
36	LVD New Business Capacity	beardslee rd gvl AG clo	2	1	Project	New Business Capacity Request	GREENVILLE	Increase capacity to meet customer demand
37	LVD New Business Capacity	SYLVAN RD, CHELSEA - ECNC UPU	2	1	Project	New Business Capacity Request	CHELSEA	Increase capacity to meet customer demand
38	LVD New Business Capacity	MONROE AVE NW-	10	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
39	LVD New Business Capacity	TH AVE CLO	1	1	Project	New Business Capacity Request	GRAND HAVEN	Increase capacity to meet customer demand
40	LVD New Business Capacity	TH AVE UPO	0	1	Project	New Business Capacity Request	GRAND HAVEN	Increase capacity to meet customer demand
41	LVD New Business Capacity	MILBOURNE AVE, FLT ECNC CLU	5	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
42	LVD New Business Capacity	S WEST BAY SHORE DR TC - UPU	12	1	Project	New Business Capacity Request	TRAVERSE CITY	Increase capacity to meet customer demand
43	LVD New Business Capacity	SHANER AVE NE, CEDAR SPRINGS	1	1	Project	New Business Capacity Request	CEDAR SPRINGS	Increase capacity to meet customer demand
44	LVD New Business Capacity	WILSON RD CLO	1	1	Project	New Business Capacity Request	NORTON SHORES	Increase capacity to meet customer demand
45	LVD New Business Capacity	WILSON RD UPU	0	1	Project	New Business Capacity Request	NORTON SHORES	Increase capacity to meet customer demand
46	LVD New Business Capacity	W SILVER LAKE RD N TC - CLO	1	1	Project	New Business Capacity Request	TRAVERSE CITY	Increase capacity to meet customer demand
47	LVD New Business Capacity	W WIELAND RD, ECNC CLO	3	1	Project	New Business Capacity Request	LANSING	Increase capacity to meet customer demand
48	LVD New Business Capacity	BORTON AVE ESEX ECNC CLO	6	1	Project	New Business Capacity Request	ESSEXVILLE	Increase capacity to meet customer demand
49	LVD New Business Capacity	STATE RD CLO	4	1	Project	New Business Capacity Request	SPRING LAKE	Increase capacity to meet customer demand
50	LVD New Business Capacity	BEACH ST CLU	11	1	Project	New Business Capacity Request	MUSKEGON	Increase capacity to meet customer demand
51	LVD New Business Capacity	W SHERMAN BLVD UPO	1	1	Project	New Business Capacity Request	MUSKEGON	Increase capacity to meet customer demand
52	LVD New Business Capacity	ASH HOLLOW DR CLSE ECNC CLO	0	1	Project	New Business Capacity Request	CHELSEA	Increase capacity to meet customer demand
53	LVD New Business Capacity	HAMPTON RD, HRSN ECNC CLU RV PARK	1	1	Project	New Business Capacity Request	HARRISON	Increase capacity to meet customer demand
54	LVD New Business Capacity	S OGEMAW TRL WBR ECNC CLO	7	1	Project	New Business Capacity Request	WEST BRANCH	Increase capacity to meet customer demand
55	LVD New Business Capacity	MILE RD - CLO	3	1	Project	New Business Capacity Request	REED CITY	Increase capacity to meet customer demand
		LVD New Business Capacity Subtotal	**301**					

MICHIGAN PUBLIC SERVICE COMMISSION
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($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	PINE POINT RD TC ECNC CLO	1	1	Project	New Business Capacity Request	TRAVERSE CITY	Increase capacity to meet customer demand
2	LVD New Business Capacity	PLAINFIELD RD, MT PLSNT ECNC CLU	4	1	Project	New Business Capacity Request	MOUNT PLEASANT	Increase capacity to meet customer demand
3	LVD New Business Capacity	W MICHIGAN AVE-GYLG - ECNC UPU	1	1	Project	New Business Capacity Request	GRAYLING	Increase capacity to meet customer demand
4	LVD New Business Capacity	W BURT RD, BRNT ECNC CLO	3	1	Project	New Business Capacity Request	BRANT	Increase capacity to meet customer demand
5	LVD New Business Capacity	W BRISTOL RD, FLT ECNC CLU	3	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
6	LVD New Business Capacity	N PINGREE RD, AL, ECNC CLO REHAB	2	1	Project	New Business Capacity Request	ALMA	Increase capacity to meet customer demand
7	LVD New Business Capacity	Hoxeyville Rd, WLTN CLO	1	1	Project	New Business Capacity Request	WELLSTON	Increase capacity to meet customer demand
8	LVD New Business Capacity	N LAKE ST BYNC CLO	4	1	Project	New Business Capacity Request	BOYNE CITY	Increase capacity to meet customer demand
9	LVD New Business Capacity	Indian Lake Rd NATC CLO	10	1	Project	New Business Capacity Request	NATIONAL CITY	Increase capacity to meet customer demand
10	LVD New Business Capacity	BELL ST, CENTRAL LAKE - CLO	4	1	Project	New Business Capacity Request	CENTRAL LAKE	Increase capacity to meet customer demand
11	LVD New Business Capacity	S BAILEY LAKEAVE RC ,GLWN ECNC UPU	2	1	Project	New Business Capacity Request	GLADWIN	Increase capacity to meet customer demand
12	LVD New Business Capacity	S FARLEY RD MGER ECNC CLO	5	1	Project	New Business Capacity Request	MUNGER	Increase capacity to meet customer demand
13	LVD New Business Capacity	TH ST FENN - ECNC CLO	12	1	Project	New Business Capacity Request	FENNVILLE	Increase capacity to meet customer demand
14	LVD New Business Capacity	TH ST FENN - ECNC UPO	1	1	Project	New Business Capacity Request	FENNVILLE	Increase capacity to meet customer demand
15	LVD New Business Capacity	RIDGE RD GARAGE, KZO - ECNC CLO	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
16	LVD New Business Capacity	LAKESHORE DR, FENN, ECNC CLO	1	1	Project	New Business Capacity Request	FENNVILLE	Increase capacity to meet customer demand
17	LVD New Business Capacity	MANOR RD, AUGS, ECNC CLO	29	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
18	LVD New Business Capacity	Oak Forest Ln SE----UPGRADE UGSV *	1	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
19	LVD New Business Capacity	DIVISION ST - ADRN - ECNC CLO	1	1	Project	New Business Capacity Request	ADRIAN	Increase capacity to meet customer demand
20	LVD New Business Capacity	MILL ST Cheboygan CLU *ESCALATION*	20	1	Project	New Business Capacity Request	CHEBOYGAN	Increase capacity to meet customer demand
21	LVD New Business Capacity	MILL ST Cheboygan UPU *ESCALATION*	3	1	Project	New Business Capacity Request	CHEBOYGAN	Increase capacity to meet customer demand
22	LVD New Business Capacity	RYNO RD LZRN ECNC UPU *AG	3	1	Project	New Business Capacity Request	LUZERNE	Increase capacity to meet customer demand
23	LVD New Business Capacity	S DORT HWY FLT ECNC CLU	9	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
24	LVD New Business Capacity	BLACKMORE ST SAG ECNC CLO	13	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
25	LVD New Business Capacity	BLACKMORE ST SAG ECNC UPO	0	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
26	LVD New Business Capacity	CHICKERING RD - ECNC CLO	62	1	Project	New Business Capacity Request	BELDING	Increase capacity to meet customer demand
27	LVD New Business Capacity	TWIN LAKES AVE, LAKE ECNC CLO	21	1	Project	New Business Capacity Request	LAKE	Increase capacity to meet customer demand
28	LVD New Business Capacity	TWIN LAKES AVE, LAKE ECNC UPO	1	1	Project	New Business Capacity Request	LAKE	Increase capacity to meet customer demand
29	LVD New Business Capacity	N ATHEY AVE, HRSN ECNC CLO	10	1	Project	New Business Capacity Request	HARRISON	Increase capacity to meet customer demand
30	LVD New Business Capacity	BONNELL AVE SE - CLO	2	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
31	LVD New Business Capacity	E SWEDE RD, SPRUCE, ECNC CLU	9	1	Project	New Business Capacity Request	SPRUCE	Increase capacity to meet customer demand
32	LVD New Business Capacity	E Center St Hastings ECNC CLO	5	1	Project	New Business Capacity Request	HASTINGS	Increase capacity to meet customer demand
33	LVD New Business Capacity	E Center St Hastings ECNC UPU	2	1	Project	New Business Capacity Request	HASTINGS	Increase capacity to meet customer demand
34	LVD New Business Capacity	CARR ST FLT ECNC CLO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
35	LVD New Business Capacity	CARR ST FLT ECNC UPO	0	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
36	LVD New Business Capacity	TH AVE - ECNC CLO *see notes	36	1	Project	New Business Capacity Request	ALLEGAN	Increase capacity to meet customer demand
37	LVD New Business Capacity	N EUCLID AVE BCY BARN ECNC RLO	1	1	Project	New Business Capacity Request	BAY CITY	Increase capacity to meet customer demand
38	LVD New Business Capacity	ROUND LAKE HWY CLO	2	1	Project	New Business Capacity Request	MANITOU BEACH	Increase capacity to meet customer demand
39	LVD New Business Capacity	S POSEYVILLE RD MID ECNC CLO	3	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
40	LVD New Business Capacity	RIVERSIDE BLVD SAG ECNC CLO	7	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
41	LVD New Business Capacity	BONNELL AVE SE, EGR, ECNC CLO	10	1	Project	New Business Capacity Request	EAST GRAND RAPIDS	Increase capacity to meet customer demand
42	LVD New Business Capacity	E WHITEFEATHER RD PCNG ECNC CLO	40	1	Project	New Business Capacity Request	PINCONNING	Increase capacity to meet customer demand
43	LVD New Business Capacity	N SAGINAW St, FLT BERSTON ECNC CLU	8	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
44	LVD New Business Capacity	E PROSPER RD, FLMT - ECNC CLO	0	1	Project	New Business Capacity Request	FALMOUTH	Increase capacity to meet customer demand
45	LVD New Business Capacity	E PROSPER RD, FLMT - ECNC UPU	4	1	Project	New Business Capacity Request	FALMOUTH	Increase capacity to meet customer demand
46	LVD New Business Capacity	W TERRITORIAL RD CLO	1	1	Project	New Business Capacity Request	BATTLE CREEK	Increase capacity to meet customer demand
47	LVD New Business Capacity	TORREY RD, FLT ECNC CLO	3	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
48	LVD New Business Capacity	N BYRON RD CUNA ECNC CLO	1	1	Project	New Business Capacity Request	CORUNNA	Increase capacity to meet customer demand
49	LVD New Business Capacity	N BYRON RD CUNA ECNC UPU	2	1	Project	New Business Capacity Request	CORUNNA	Increase capacity to meet customer demand
50	LVD New Business Capacity	DUBLIN AVE	4	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
51	LVD New Business Capacity	TH AVE - CLO	1	1	Project	New Business Capacity Request	ZEELAND	Increase capacity to meet customer demand
52	LVD New Business Capacity	STADIUM DR, KZO - ECNC CLO *	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
53	LVD New Business Capacity	STADIUM DR, KZO - ECNC UPU * *JS	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
54	LVD New Business Capacity	STADIUM DR, KZO-ADDED EV CHARGERS *	5	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
55	LVD New Business Capacity	S STRAITS HWY CLO	8	1	Project	New Business Capacity Request	INDIAN RIVER	Increase capacity to meet customer demand
56		**LVD New Business Capacity Subtotal**	**386**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	S STRAITS HWY UPO	1	1	Project	New Business Capacity Request	INDIAN RIVER	Increase capacity to meet customer demand
2	LVD New Business Capacity	PRETTY LAKE HGHTS, MTWN ECNC CLO	4	1	Project	New Business Capacity Request	MATTAWAN	Increase capacity to meet customer demand
3	LVD New Business Capacity	SPARKS DR SE - CLU	3	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
4	LVD New Business Capacity	N AVERILL AVE- BLDG - ECNC/UPU	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
5	LVD New Business Capacity	N AVERILL AVE- BLDG - ECNC/UPU	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
6	LVD New Business Capacity	WADSWORTH RD SAG ECNC CLO REHAB	1	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
7	LVD New Business Capacity	ST AVE - ECNC CLO	5	1	Project	New Business Capacity Request	HAMILTON	Increase capacity to meet customer demand
8	LVD New Business Capacity	ELDER ST PSCT ECNC CLO	1	1	Project	New Business Capacity Request	PRESCOTT	Increase capacity to meet customer demand
9	LVD New Business Capacity	ELDER ST PSCT ECNC UPO	0	1	Project	New Business Capacity Request	PRESCOTT	Increase capacity to meet customer demand
10	LVD New Business Capacity	TRAVERSE ST EKRP ECNC CLO	8	1	Project	New Business Capacity Request	ELK RAPIDS	Increase capacity to meet customer demand
11	LVD New Business Capacity	Donnely Road CLO	1	1	Project	New Business Capacity Request	JACKSON	Increase capacity to meet customer demand
12	LVD New Business Capacity	N DOROTHY DR SANFORD ECNC CLO	3	1	Project	New Business Capacity Request	SANFORD	Increase capacity to meet customer demand
13	LVD New Business Capacity	TWO MILE RD, UPGRADE UG ELEC LINE	3	1	Project	New Business Capacity Request	BAY CITY	Increase capacity to meet customer demand
14	LVD New Business Capacity	CALHOUN RD BVRTN ECNC CLO REHAB	4	1	Project	New Business Capacity Request	BEAVERTON	Increase capacity to meet customer demand
15	LVD New Business Capacity	BARRY ST, HUDV, ECNC CLO	3	1	Project	New Business Capacity Request	HUDSONVILLE	Increase capacity to meet customer demand
16	LVD New Business Capacity	MALONEY RD PNCG ECNC CLO	1	1	Project	New Business Capacity Request	PINCONNING	Increase capacity to meet customer demand
17	LVD New Business Capacity	THORNAPPLE RIVER DR SE - ECNO RSU	2	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
18	LVD New Business Capacity	S BLUFF LN CDR - CLU	2	1	Project	New Business Capacity Request	CEDAR	Increase capacity to meet customer demand
19	LVD New Business Capacity	ANN ST NW - ECNC CLU	26	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
20	LVD New Business Capacity	MICHIGAN ST NE- RSU	3	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
21	LVD New Business Capacity	COURT ST SAG ECNC UPO	10	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
22	LVD New Business Capacity	N CLARE AVE, HRSN ECNC CLO	3	1	Project	New Business Capacity Request	HARRISON	Increase capacity to meet customer demand
23	LVD New Business Capacity	N CLARE AVE, HRSN ECNC UPO	0	1	Project	New Business Capacity Request	HARRISON	Increase capacity to meet customer demand
24	LVD New Business Capacity	th St SE-CLU	5	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
25	LVD New Business Capacity	GRAYSTONE DR OKEM ECNC CLU	2	1	Project	New Business Capacity Request	OKEMOS	Increase capacity to meet customer demand
26	LVD New Business Capacity	SKIRROW PL, ECNC CLO	7	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
27	LVD New Business Capacity	W RD #B MSCK ECNC CLO	0	1	Project	New Business Capacity Request	MESICK	Increase capacity to meet customer demand
28	LVD New Business Capacity	DAVISON RD, BTN ECNC CLO PART	174	1	Project	New Business Capacity Request	BURTON	Increase capacity to meet customer demand
29	LVD New Business Capacity	DAVISON RD, BTN ECNC CLO PART	67	1	Project	New Business Capacity Request	BURTON	Increase capacity to meet customer demand
30	LVD New Business Capacity	DAVISON RD, BTN ECNC SWITCH	-	1	Project	New Business Capacity Request	BURTON	Increase capacity to meet customer demand
31	LVD New Business Capacity	WILDWOOD RD, ALGER ECNC CLO_GLW CO	3	1	Project	New Business Capacity Request	ALGER	Increase capacity to meet customer demand
32	LVD New Business Capacity	N BAY MID SHED, MID ECNC CLO	13	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
33	LVD New Business Capacity	NE TORCH LAKE DR, CNLK - ECNC CLO	116	1	Project	New Business Capacity Request	CENTRAL LAKE	Increase capacity to meet customer demand
34	LVD New Business Capacity	KNAPP ST NE - CLO	61	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
35	LVD New Business Capacity	KNAPP ST NE - CLU	2	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
36	LVD New Business Capacity	NORTHLAND DR, GLDWN ECNC CLO	5	1	Project	New Business Capacity Request	GLADWIN	Increase capacity to meet customer demand
37	LVD New Business Capacity	N LOOMIS RD, MT PLSNT ECNC CLO	5	1	Project	New Business Capacity Request	MOUNT PLEASANT	Increase capacity to meet customer demand
38	LVD New Business Capacity	E DRESDEN ST im des, L Mueller	0	1	Project	New Business Capacity Request	KALKASKA	Increase capacity to meet customer demand
39	LVD New Business Capacity	WILDWOOD DR, GLDWN ECNC CLO	2	1	Project	New Business Capacity Request	GLADWIN	Increase capacity to meet customer demand
40	LVD New Business Capacity	S HURON RD, STANDISH ECNC CLO	2	1	Project	New Business Capacity Request	STANDISH	Increase capacity to meet customer demand
41	LVD New Business Capacity	N STATE RD DAVISON ECNC CLO	1	1	Project	New Business Capacity Request	DAVISON	Increase capacity to meet customer demand
42	LVD New Business Capacity	MARSHALL ST, LITF ECNC CLO	3	1	Project	New Business Capacity Request	LITCHFIELD	Increase capacity to meet customer demand
43	LVD New Business Capacity	PILGRIM RD, FLT ECNC CLU	14	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
44	LVD New Business Capacity	W WEINERT RD COLEMAN ECNC CLO	5	1	Project	New Business Capacity Request	COLEMAN	Increase capacity to meet customer demand
45	LVD New Business Capacity	W WEINERT RD COLEMAN ECNC UPU	2	1	Project	New Business Capacity Request	COLEMAN	Increase capacity to meet customer demand
46	LVD New Business Capacity	W BROWNLEE RD SANFORD ECNC CLO	1	1	Project	New Business Capacity Request	SANFORD	Increase capacity to meet customer demand
47	LVD New Business Capacity	TH AVE BANGOR ECNC CLO	1	1	Project	New Business Capacity Request	BANGOR	Increase capacity to meet customer demand
48	LVD New Business Capacity	GREENWOOD RD PB PSCT ECNC CLO	2	1	Project	New Business Capacity Request	PRESCOTT	Increase capacity to meet customer demand
49	LVD New Business Capacity	US HIGHWAY N, WILLIAMSBURG CLO	14	1	Project	New Business Capacity Request	WILLIAMSBURG	Increase capacity to meet customer demand
50	LVD New Business Capacity	EXECUTIVE PKWY SE - ADDING LOAD	11	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
51	LVD New Business Capacity	HUPP AVE, JACKSON - ECNC CLO	8	1	Project	New Business Capacity Request	JACKSON	Increase capacity to meet customer demand
52	LVD New Business Capacity	Ada Dr----ECNC NLO	0	1	Project	New Business Capacity Request	ADA	Increase capacity to meet customer demand
53	LVD New Business Capacity	CEDAR ST, WLR - ECNC CLO	1	1	Project	New Business Capacity Request	WOLVERINE	Increase capacity to meet customer demand
54	LVD New Business Capacity	N CHIPPEWA RD, CLMN ECNC CLO	1	1	Project	New Business Capacity Request	COLEMAN	Increase capacity to meet customer demand
55	LVD New Business Capacity	W RIVER DR NE CLO	7	1	Project	New Business Capacity Request	BELMONT	Increase capacity to meet customer demand
56		**LVD New Business Capacity Subtotal**	**619**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	W RIVER DR NE NSU	6	1	Project	New Business Capacity Request	BELMONT	Increase capacity to meet customer demand
2	LVD New Business Capacity	RAVINE RD, KZO - ECNC CLO	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
3	LVD New Business Capacity	OLCOTT LK, JACKSON - ECNC CLO	1	1	Project	New Business Capacity Request	JACKSON	Increase capacity to meet customer demand
4	LVD New Business Capacity	WORTH RD, STDH, ECNC CLO	5	1	Project	New Business Capacity Request	STANDISH	Increase capacity to meet customer demand
5	LVD New Business Capacity	RD ST ERET	1	1	Project	New Business Capacity Request	MUSKEGON	Increase capacity to meet customer demand
6	LVD New Business Capacity	E PARIS AVE SE - UPU	1	1	Project	New Business Capacity Request	CALEDONIA	Increase capacity to meet customer demand
7	LVD New Business Capacity	STONY RUN - HOLLY	350	1	Project	New Business Capacity Request	HOLLY	Increase capacity to meet customer demand
8	LVD New Business Capacity	BLUFF LAKE RD, LAKE ECNC CLO	4	1	Project	New Business Capacity Request	LAKE	Increase capacity to meet customer demand
9	LVD New Business Capacity	GRACE AVE CLO	1	1	Project	New Business Capacity Request	LUDINGTON	Increase capacity to meet customer demand
10	LVD New Business Capacity	W GERWOUDE DR, MCBN - ECNC CLO	34	1	Project	New Business Capacity Request	MCBAIN	Increase capacity to meet customer demand
11	LVD New Business Capacity	E LAKE DR HSLT, ECNC CLO	1	1	Project	New Business Capacity Request	HASLETT	Increase capacity to meet customer demand
12	LVD New Business Capacity	CODYLYNN DR UPO / SERVICE UPGR	1	1	Project	New Business Capacity Request	MUSKEGON	Increase capacity to meet customer demand
13	LVD New Business Capacity	SYLVAN DR, GLW ECNC CLO	5	1	Project	New Business Capacity Request	GLADWIN	Increase capacity to meet customer demand
14	LVD New Business Capacity	N SCHOOL RD, SPRUCE, ECNC CLO	3	1	Project	New Business Capacity Request	SPRUCE	Increase capacity to meet customer demand
15	LVD New Business Capacity	S ELM AVE WTEC ECNC CLO	1	1	Project	New Business Capacity Request	WHITE CLOUD	Increase capacity to meet customer demand
16	LVD New Business Capacity	ND AVE CLO *COMMITTED //	2	1	Project	New Business Capacity Request	WEST OLIVE	Increase capacity to meet customer demand
17	LVD New Business Capacity	HARTWOOD DR FNT ECNC CLO	3	1	Project	New Business Capacity Request	FENTON	Increase capacity to meet customer demand
18	LVD New Business Capacity	HARTWOOD DR FNT ECNC UPO	0	1	Project	New Business Capacity Request	FENTON	Increase capacity to meet customer demand
19	LVD New Business Capacity	WILSON RD CLO	1	1	Project	New Business Capacity Request	NUNICA	Increase capacity to meet customer demand
20	LVD New Business Capacity	N US HIGHWAY CLU	3	1	Project	New Business Capacity Request	FREE SOIL	Increase capacity to meet customer demand
21	LVD New Business Capacity	S IVA RD, STCH ECNC CLO	1	1	Project	New Business Capacity Request	SAINT CHARLES	Increase capacity to meet customer demand
22	LVD New Business Capacity	DOWNING HWY BRITTON ECNC CLO	18	1	Project	New Business Capacity Request	BRITTON	Increase capacity to meet customer demand
23	LVD New Business Capacity	N MILE RD CLMN - ECNC CLO	6	1	Project	New Business Capacity Request	COLEMAN	Increase capacity to meet customer demand
24	LVD New Business Capacity	N MILE RD CLMN - ECNC UPU	2	1	Project	New Business Capacity Request	COLEMAN	Increase capacity to meet customer demand
25	LVD New Business Capacity	MEADOWBROOK DR - UG COST ESTIMATE	18	1	Project	New Business Capacity Request	HUDSON	Increase capacity to meet customer demand
26	LVD New Business Capacity	Jose Lake Rd SBR ECNC CLO	2	1	Project	New Business Capacity Request	SOUTH BRANCH	Increase capacity to meet customer demand
27	LVD New Business Capacity	COOK RD SRTZ ECNC CLO	1	1	Project	New Business Capacity Request	SWARTZ CREEK	Increase capacity to meet customer demand
28	LVD New Business Capacity	S MAIN ST, IM Des M Witt	9	1	Project	New Business Capacity Request	WAYLAND	Increase capacity to meet customer demand
29	LVD New Business Capacity	S ROSE ST, KZO - ECNC CLO	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
30	LVD New Business Capacity	S ROSE ST, KZO - ECNC UPO	3	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
31	LVD New Business Capacity	E RD ST EKRP ECNC CLU	16	1	Project	New Business Capacity Request	ELK RAPIDS	Increase capacity to meet customer demand
32	LVD New Business Capacity	S DUNNS FARM RD MPL - NLO	1	1	Project	New Business Capacity Request	MAPLE CITY	Increase capacity to meet customer demand
33	LVD New Business Capacity	GRAND HAVEN RD - CLO	3	1	Project	New Business Capacity Request	NORTON SHORES	Increase capacity to meet customer demand
34	LVD New Business Capacity	GRAND HAVEN RD - UPU	2	1	Project	New Business Capacity Request	NORTON SHORES	Increase capacity to meet customer demand
35	LVD New Business Capacity	industrial park dr gvl CLU	76	1	Project	New Business Capacity Request	GREENVILLE	Increase capacity to meet customer demand
36	LVD New Business Capacity	SHERIDAN RD FLSH ECNC UPU	1	1	Project	New Business Capacity Request	FLUSHING	Increase capacity to meet customer demand
37	LVD New Business Capacity	SHERIDAN RD FLSH ECNO CLU	4	1	Project	New Business Capacity Request	FLUSHING	Increase capacity to meet customer demand
38	LVD New Business Capacity	MEINERT RD HLTN - CLO	4	1	Project	New Business Capacity Request	HOLTON	Increase capacity to meet customer demand
39	LVD New Business Capacity	MEINERT RD HLTN REHAB - CLO	2	1	Project	New Business Capacity Request	HOLTON	Increase capacity to meet customer demand
40	LVD New Business Capacity	N ALGER RD, AL, ECNC CLU REHAB	2	1	Project	New Business Capacity Request	ALMA	Increase capacity to meet customer demand
41	LVD New Business Capacity	LAKEVIEW DR, CLARKLAKE - ECNC CLO	0	1	Project	New Business Capacity Request	CLARK LAKE	Increase capacity to meet customer demand
42	LVD New Business Capacity	E H AVE ECNC CLO	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
43	LVD New Business Capacity	W HOUGHTON LAKE DR-HTNL-CLU-Nesters	2	1	Project	New Business Capacity Request	HOUGHTON LAKE	Increase capacity to meet customer demand
44	LVD New Business Capacity	Ingleston Dr BULA - CLO	1	1	Project	New Business Capacity Request	BEULAH	Increase capacity to meet customer demand
45	LVD New Business Capacity	N CRAM RD, OWS - ECNC CLO	33	1	Project	New Business Capacity Request	OWOSSO	Increase capacity to meet customer demand
46	LVD New Business Capacity	N CRAM RD, OWS - ECNC CLO	53	1	Project	New Business Capacity Request	OWOSSO	Increase capacity to meet customer demand
47	LVD New Business Capacity	N CRAM RD, OWS - ECNC CLO	77	1	Project	New Business Capacity Request	OWOSSO	Increase capacity to meet customer demand
48	LVD New Business Capacity	PENINSULA DR TC CLO	1	1	Project	New Business Capacity Request	TRAVERSE CITY	Increase capacity to meet customer demand
49	LVD New Business Capacity	BILLMYER HWY - TCSH - ECNC CLO	1	1	Project	New Business Capacity Request	TECUMSEH	Increase capacity to meet customer demand
50	LVD New Business Capacity	N WATER ST, WLER, ECNC CLU	3	1	Project	New Business Capacity Request	WHEELER	Increase capacity to meet customer demand
51	LVD New Business Capacity	MAPLE GROVE RD, LAKE ECNC CLO	18	1	Project	New Business Capacity Request	LAKE	Increase capacity to meet customer demand
52	LVD New Business Capacity	breezy pt clkv clo *Carded outage	6	1	Project	New Business Capacity Request	CLARKSVILLE	Increase capacity to meet customer demand
53	LVD New Business Capacity	E MAPLE RAPIDS RD, ELSE, ECNC CLO	1	1	Project	New Business Capacity Request	ELSIE	Increase capacity to meet customer demand
54	LVD New Business Capacity	TH ST - CLO	2	1	Project	New Business Capacity Request	HOWARD CITY	Increase capacity to meet customer demand
55	LVD New Business Capacity	WIGGINS RD ECNC CLO	2	1	Project	New Business Capacity Request	HOWELL	Increase capacity to meet customer demand
56		**LVD New Business Capacity Subtotal**	**795**					

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($000)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
Page: 36 of 37
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	BRIARCLIFF RD, ECNC UPU	9	1	Project	New Business Capacity Request	JACKSON	Increase capacity to meet customer demand
2	LVD New Business Capacity	TOWER RD Unit D MPL - CLU	2	1	Project	New Business Capacity Request	MAPLE CITY	Increase capacity to meet customer demand
3	LVD New Business Capacity	TOWER RD Unit D MPL - UPU	1	1	Project	New Business Capacity Request	MAPLE CITY	Increase capacity to meet customer demand
4	LVD New Business Capacity	VALLEY RD RPID ECNC CLO	1	1	Project	New Business Capacity Request	RAPID CITY	Increase capacity to meet customer demand
5	LVD New Business Capacity	E WEST BRANCH RD ST HELEN ECNC CLO	2	1	Project	New Business Capacity Request	SAINT HELEN	Increase capacity to meet customer demand
6	LVD New Business Capacity	N TH ST ECNC CLO	1	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
7	LVD New Business Capacity	N TH ST, KZOO, ECNC CLO	6	1	Project	New Business Capacity Request	KALAMAZOO	Increase capacity to meet customer demand
8	LVD New Business Capacity	N FINLEY LAKE AVE HRS ECNC CLU	4	1	Project	New Business Capacity Request	HARRISON	Increase capacity to meet customer demand
9	LVD New Business Capacity	KENOWA DIST BARN	0	1	Project	New Business Capacity Request	SPARTA	Increase capacity to meet customer demand
10	LVD New Business Capacity	LAKESHORE DR REHAB OHL	29	1	Project	New Business Capacity Request	WEST OLIVE	Increase capacity to meet customer demand
11	LVD New Business Capacity	ALLENDALE PT RP SVC BROWN	2	1	Project	New Business Capacity Request	ALLENDALE	Increase capacity to meet customer demand
12	LVD New Business Capacity	DENNISON CLO - NUNICA _SECT	217	1	Project	New Business Capacity Request	NUNICA	Increase capacity to meet customer demand
13	LVD New Business Capacity	DENNISON CLO - NUNICA_ SECT	107	1	Project	New Business Capacity Request	CROCKERY TOWNSHIP	Increase capacity to meet customer demand
14	LVD New Business Capacity	DENNISON CLU - NUNICA _SECT UGL	2	1	Project	New Business Capacity Request	NUNICA	Increase capacity to meet customer demand
15	LVD New Business Capacity	DENNISON CLU - NUNICA_ SECT UGL	12	1	Project	New Business Capacity Request	CROCKERY TOWNSHIP	Increase capacity to meet customer demand
16	LVD New Business Capacity	DENNISON SUB VOLT CONV SECT	185	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
17	LVD New Business Capacity	DENNISON SUB VOLT CONV SECT B	172	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
18	LVD New Business Capacity	DENNISON SUB VOLT CONVERSION SECT UG	34	1	Project	New Business Capacity Request	COOPERSVILLE	Increase capacity to meet customer demand
19	LVD New Business Capacity	DENNISON SUB VOLTAGE CONV SECT UG	5	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
20	LVD New Business Capacity	DENNISON SUB VOLTAGE CONV SECT UG	8	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
21	LVD New Business Capacity	DENNISON SUB VOLTAGE CONV SECT A	217	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
22	LVD New Business Capacity	DENNISON SUB VOLTAGE CONV SECT A	93	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
23	LVD New Business Capacity	DENNISON SUB VOLTAGE CONV SECT B	72	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
24	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT	121	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
25	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT	89	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
26	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT	138	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
27	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT	172	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
28	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT	179	1	Project	New Business Capacity Request	COOPERSVILLE	Increase capacity to meet customer demand
29	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT	129	1	Project	New Business Capacity Request	RAVENNA TOWNSHIP	Increase capacity to meet customer demand
30	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT b	33	1	Project	New Business Capacity Request	RAVENNA TOWNSHIP	Increase capacity to meet customer demand
31	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT c	8	1	Project	New Business Capacity Request	RAVENNA TOWNSHIP	Increase capacity to meet customer demand
32	LVD New Business Capacity	DENNISON SUB VOLTAGE CONVERSION SECT B	21	1	Project	New Business Capacity Request	POLKTON TOWNSHIP	Increase capacity to meet customer demand
33	LVD New Business Capacity	ECNC CLO - NUNICA_ SECT UGL	1	1	Project	New Business Capacity Request	NUNICA	Increase capacity to meet customer demand
34	LVD New Business Capacity	EWO - E DIANE DR CLU	4	1	Project	New Business Capacity Request	CAMDEN	Increase capacity to meet customer demand
35	LVD New Business Capacity	LNAG SANT.-E TAWAS-COTGE %LVD P--	30	1	Project	New Business Capacity Request	AU GRES TOWNSHIP	Increase capacity to meet customer demand
36	LVD New Business Capacity	LNAG SANTIAGO- SWENSON RD	2	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
37	LVD New Business Capacity	LNAG SANTIAGO- SWENSON RD	3	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
38	LVD New Business Capacity	LNAG SANTIAGO- W MICHIGAN AVE	1	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
39	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTG LVD RM ISO	4	1	Project	New Business Capacity Request	AU GRES TOWNSHIP	Increase capacity to meet customer demand
40	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	944	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
41	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	320	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
42	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	308	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
43	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	275	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
44	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	153	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
45	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	24	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
46	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	25	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
47	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	38	1	Project	New Business Capacity Request	AU GRES TOWNSHIP	Increase capacity to meet customer demand
48	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE %LVD P-	3	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
49	LVD New Business Capacity	LNAG SANTIAGO-E TAWAS-COTGE LVD P-UG	7	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
50	LVD New Business Capacity	LTOE Saginaw ST Building D	22	1	Project	New Business Capacity Request	BURTON	Increase capacity to meet customer demand
51	LVD New Business Capacity	NBCAP Hawthorne-CKT RR X-ing CLU	15	1	Project	New Business Capacity Request	WALKER	Increase capacity to meet customer demand
52	LVD New Business Capacity	NBCAP Hawthorne-CKT,,-LOC-,,-	503	1	Project	New Business Capacity Request	WALKER	Increase capacity to meet customer demand
53	LVD New Business Capacity	NBUS Kentwood Princeton LCP * NOV	78	1	Project	New Business Capacity Request	KENTWOOD	Increase capacity to meet customer demand
54	LVD New Business Capacity	OTTAWA COUNTY JUSTICE CENTER EXP	52	1	Project	New Business Capacity Request	OLIVE TOWNSHIP	Increase capacity to meet customer demand
55	LVD New Business Capacity	RIVERBEND_HALE ROAD SUB PT	186	1	Project	New Business Capacity Request	OMER	Increase capacity to meet customer demand
56	LVD New Business Capacity	RIVERBEND_HALE- HIGH OHS	0	1	Project	New Business Capacity Request	OMER	Increase capacity to meet customer demand
57	LVD New Business Capacity	RIVERBEND_HALEemail storeroom	150	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
58	LVD New Business Capacity	RIVERBEND_OMER SUB - PART	60	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
59	LVD New Business Capacity	RIVERBEND_OMER SUB - PART .	24	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
60	LVD New Business Capacity	RIVERBEND_OMER SUB - PART .	70	1	Project	New Business Capacity Request	ARENAC TOWNSHIP	Increase capacity to meet customer demand
61	LVD New Business Capacity	SANTIAGO CIRCUIT EXITS	361	1	Project	New Business Capacity Request	AU GRES TOWNSHIP	Increase capacity to meet customer demand
62	LVD New Business Capacity	SANTIAGO_SAINT JAMES W HURON RD	3	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
63	LVD New Business Capacity	SANTIAGO_SAINT JAMES SUB ECNC CLU	16	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
64	LVD New Business Capacity	SANTIAGO_SAINT JAMES SUB SHT	53	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
65	LVD New Business Capacity	SANTIAGO_SAINT JAMES SUB SHT	28	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
66	LVD New Business Capacity	SANTIAGO_SAINT JAMES SUB SHT	60	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
67	LVD New Business Capacity	SANTIAGO_SAINT JAMES SUB SHT-	20	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
68	LVD New Business Capacity	SANTIAGO_SAINT JAMES SUB SHT	29	1	Project	New Business Capacity Request	AU GRES	Increase capacity to meet customer demand
69	LVD New Business Capacity	STEVENS/STEVENS NEW CKT -PART	111	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
70	LVD New Business Capacity	STEVENS/STEVENS NEW CKT -PART	125	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
71	LVD New Business Capacity	STEVENS/STEVENS NEW CKT -PART B	47	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
72	LVD New Business Capacity	STONEY CORNERS / STONE LEDGE PART DEM	3	1	Project	New Business Capacity Request	CADILLAC	Increase capacity to meet customer demand
73	LVD New Business Capacity	STONEY CORNERS / STONE LEDGE PART DEM	2	1	Project	New Business Capacity Request	CADILLAC	Increase capacity to meet customer demand
74	LVD New Business Capacity	STONEY CORNERS / STONE LEDGE PART DEMO	7	1	Project	New Business Capacity Request	CADILLAC	Increase capacity to meet customer demand
75	LVD New Business Capacity	TERRA NOVA DEVELOPMENT - NBUS CLO	56	1	Project	New Business Capacity Request	ADA	Increase capacity to meet customer demand
76	LVD New Business Capacity	Villages of Silver Lake Development	64	1	Project	New Business Capacity Request	ROCKFORD	Increase capacity to meet customer demand
77	LVD New Business Capacity	WAGARVILLE RD AND M ECNC NBREHAB	4	1	Project	New Business Capacity Request	GLADWIN	Increase capacity to meet customer demand
78		**LVD New Business Capacity Subtotal**	**6,362**					
79		**LVD New Business Capacity Total**	**8,463**					

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2026
($5,586)

Case No.: U-21870
Exhibit No.: A-166 (JMP-1)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	Conservation Voltage Reduction	CVR_BURLINGAME_NEWHALL	65	1	Circuit	Conservation Voltage Reduction	CITY OF WYOMING	kW Energy Savings	30
2		CVR_AUBIL_TOWERS	56	1	Circuit	Conservation Voltage Reduction	LEIGHTON TOWNSHIP	kW Energy Savings	55
3		CVR_BOWEN/KIMBERLY	205	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	7
4		CVR_BOWEN/AIRCRAFT	106	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	26
5		CVR_NEWBURG_BANCROFT	96	1	Circuit	Conservation Voltage Reduction	SHIAWASSE TOWNSHIP	kW Energy Savings	16
6		CVR_STANDALE_STANDALE	120	1	Circuit	Conservation Voltage Reduction	CITY OF WALKER	kW Energy Savings	27
7		CVR_STANDALE_VILLAGE	35	1	Circuit	Conservation Voltage Reduction	CITY OF WALKER	kW Energy Savings	20
8		CVR_WEST MAIN_SOUTH ST	275	1	Circuit	Conservation Voltage Reduction	OWOSSO TOWNSHIP	kW Energy Savings	14
9		CVR_BRIDGEPORT_BRIDGEPORT	75	1	Circuit	Conservation Voltage Reduction	BRIDGEPORT TOWNSHIP	kW Energy Savings	15
10		CVR_PLAINWELL_COMMERCIAL	240	1	Circuit	Conservation Voltage Reduction	CITY OF PLAINWELL	kW Energy Savings	25
11		CVR_STANLEY_SUMMIT	55	1	Circuit	Conservation Voltage Reduction	MT MORRIS TOWNSHIP	kW Energy Savings	43
12		CVR_MANCHESTER_AUSTIN ROAD	80	1	Circuit	Conservation Voltage Reduction	CITY OF MANCHESTER	kW Energy Savings	10
13		CVR_MILLERS POINT_ARCADIA	60	1	Circuit	Conservation Voltage Reduction	CITY OF KALAMAZOO	kW Energy Savings	41
14		CVR_OAK STREET_WEST GANSON	75	1	Circuit	Conservation Voltage Reduction	CITY OF JACKSON	kW Energy Savings	49
15		CVR_OAKWOOD_PARKVIEW	175	1	Circuit	Conservation Voltage Reduction	CITY OF KALAMAZOO	kW Energy Savings	15
16		CVR_BEALS ROAD_DIVISION	180	1	Circuit	Conservation Voltage Reduction	CITY OF WYOMING	kW Energy Savings	4
17		CVR_BOSTON SQUARE_HALL	75	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	15
18		CVR_ONEKAMA_ONEKAMA	55	1	Circuit	Conservation Voltage Reduction	BEAR LAKE TOWNSHIP	kW Energy Savings	45
19		CVR_RAMONA_BLODGETT	84	1	Circuit	Conservation Voltage Reduction	CITY OF EAST GRAND RAPIDS	kW Energy Savings	57
20		CVR_CHEYENNE_GREEN ACRES	11	1	Circuit	Conservation Voltage Reduction	SAGINAW TOWNSHIP	kW Energy Savings	17
21		CVR_WEALTHY ST_GODFREY	85	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	42
22		CVR_DEWEY_SEATING	108	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	58
23		CVR_COOLEY_NORTH STREET	56	1	Circuit	Conservation Voltage Reduction	CITY OF KALAMAZOO	kW Energy Savings	15
24		CVR_KILGORE_TIMBERLANE	32	1	Circuit	Conservation Voltage Reduction	CITY OF PORTAGE	kW Energy Savings	35
25		CVR_MICHIGAN CENTER_BALLARD	25	1	Circuit	Conservation Voltage Reduction	LEONI TOWNSHIP	kW Energy Savings	15
26		CVR_GIRARD_DAYBURG	65	1	Circuit	Conservation Voltage Reduction	GIRARD TWP	kW Energy Savings	50
27		CVR_GIRARD_GIRARD	10	1	Circuit	Conservation Voltage Reduction	GIRARD TWP	kW Energy Savings	15
28		CVR_BRONSON_MILL ST	65	1	Circuit	Conservation Voltage Reduction	BRONSON TWP	kW Energy Savings	70
29		CVR_BYRON CENTER_BYRON CENTER	69	1	Circuit	Conservation Voltage Reduction	BYRON TWP	kW Energy Savings	41
30		CVR_PENNFIELD_CLEAR LAKE	19	1	Circuit	Conservation Voltage Reduction	PENNFIELD TWP	kW Energy Savings	12
31		CVR_LAKE ODESSA_INDUSTRIAL	17	1	Circuit	Conservation Voltage Reduction	ODESSA TWP	kW Energy Savings	91
32		CVR_GLENDALE_KEYES	25	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	116
33		CVR_RAVINE_PATTERSON	75	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	126
34		CVR_PARKWAY_VINE	60	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	96
35		CVR_WEST FENTON_OVERPASS	40	1	Circuit	Conservation Voltage Reduction	FENTON TWP	kW Energy Savings	112
36		CVR_DOEHLER JARVIS_GRIGGS STREET	112	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	54
37		CVR_GOODALE_ROOSEVELT	50	1	Circuit	Conservation Voltage Reduction	BEDFORD TWP	kW Energy Savings	48
38		CVR_GOGUAC_LAKEVIEW	50	1	Circuit	Conservation Voltage Reduction	BATTLE CREEK TWP	kW Energy Savings	158
39		CVR_BEECHER_TOLEDO ROAD	50	1	Circuit	Conservation Voltage Reduction	MADISON TWP	kW Energy Savings	72
40		CVR_MT PLEASANT_COLLEGE	50	1	Circuit	Conservation Voltage Reduction	UNION TWP	kW Energy Savings	155
41		CVR_BRISTOL_MILLER	100	1	Circuit	Conservation Voltage Reduction	SAGINAW	kW Energy Savings	34
42		CVR_SCHOOL ROAD_MORROCCO	35	1	Circuit	Conservation Voltage Reduction	BEDFORD TWP	kW Energy Savings	122
43		CVR_KAWKAWLIN_RUSSEL	75	1	Circuit	Conservation Voltage Reduction	KAWKAWLIN TWP	kW Energy Savings	72
44		CVR_RUSSELLVILLE_VICTORIA	100	1	Circuit	Conservation Voltage Reduction	RICHFIELD TWP	kW Energy Savings	145
45		CVR_HOGAN ROAD_HOISINGTON	85	1	Circuit	Conservation Voltage Reduction	ARGENTINE TWP	kW Energy Savings	43
46		CVR_FREMONT_REEMAN	25	1	Circuit	Conservation Voltage Reduction	SHERIDAN TWP	kW Energy Savings	130
47		CVR_PORTAGE_LOVERS LANE	65	1	Circuit	Conservation Voltage Reduction	PORTAGE TWP	kW Energy Savings	77
48		CVR_GETTY_ALLEN	75	1	Circuit	Conservation Voltage Reduction	MUSKEGON	kW Energy Savings	116
49		CVR_DORR CORNERS_100TH ST	25	1	Circuit	Conservation Voltage Reduction	DORR TWP	kW Energy Savings	154
50		CVR_TALLMAN_WACOSTA	25	1	Circuit	Conservation Voltage Reduction	EAGLE TWP	kW Energy Savings	136
51		CVR_PHILLIPS_FACTORY	25	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	76
52		CVR_VAN ATTA_POWELL	25	1	Circuit	Conservation Voltage Reduction	MERIDIAN TWP	kW Energy Savings	138
53		CVR_TECUMSEH_EVANS STREET	25	1	Circuit	Conservation Voltage Reduction	TECUMSEH TWP	kW Energy Savings	170
54		CVR_POTTERVILLE_POTTERVILLE	25	1	Circuit	Conservation Voltage Reduction	BENTON TWP	kW Energy Savings	82
55		CVR_TRAVIS_COLLINGWOOD	25	1	Circuit	Conservation Voltage Reduction	COOPER TWP	kW Energy Savings	117
56		CVR_HYDE PARK_DUCK LAKE	50	1	Circuit	Conservation Voltage Reduction	DALTON TWP	kW Energy Savings	151
57		CVR_ESSEXVILLE_CENTER ROAD	25	1	Circuit	Conservation Voltage Reduction	HAMPTON TWP	kW Energy Savings	70
58		CVR_EASTWOOD_TEXEL	75	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	98
59		CVR_WASHINGTON_FIRST STREET	35	1	Circuit	Conservation Voltage Reduction	PERE MARQUETTE TWP	kW Energy Savings	26
60		CVR_HOLLY_ACADEMY	75	1	Circuit	Conservation Voltage Reduction	HOLLY TWP	kW Energy Savings	49
61		CVR_PHILLIPS_INKSTER	25	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	117
62		CVR_BOSTON SQUARE_MULICK PARK	100	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	98
63		CVR_IVANREST_LACROSSE	50	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	47
64		CVR_STANLEY_NORTHLAND	100	1	Circuit	Conservation Voltage Reduction	MT MORRIS TWP	kW Energy Savings	78
65		CVR_RED ARROW_OGEMA	30	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	82
66		CVR_RED ARROW_MARKHAM	25	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	111
67		CVR_MAPLE GROVE_SHAW BOX	50	1	Circuit	Conservation Voltage Reduction	FRUITPORT TWP	kW Energy Savings	96
68		CVR_NAPOLEON_MOON LAKE	75	1	Circuit	Conservation Voltage Reduction	NAPOLEON TWP	kW Energy Savings	128
69		CVR_ROSE CITY_KACKLING CREEK	100	1	Circuit	Conservation Voltage Reduction	CUMMING TWP	kW Energy Savings	95
70		CVR_WHITTIM_PETRIEVILLE	50	1	Circuit	Conservation Voltage Reduction	EATON RAPIDS TWP	kW Energy Savings	24
71		CVR_SHATTUCK_COUNTY FARM	75	1	Circuit	Conservation Voltage Reduction	SAGINAW	kW Energy Savings	-
72		CVR_GROVER_TRIANGLE	75	1	Circuit	Conservation Voltage Reduction	ARCADA TWP	kW Energy Savings	-
73		CVR_DALE ROAD_M-18	75	1	Circuit	Conservation Voltage Reduction	BEAVERTON TWP	kW Energy Savings	-
74		CVR_GRANT_CATALPA	75	1	Circuit	Conservation Voltage Reduction	ASHLAND TWP	kW Energy Savings	-
75		Identified CVR Voltage Remediation Upgrades	500	1	Circuit	Conservation Voltage Reduction	MICHIGAN	kW Energy Savings	-
		CVR Total	**5,586**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
		Associated HVD Lines Project:							
1	LVD Asset Relocations	Merrill	301	4.6	Miles	Line Rebuild	Merrill	Obligation to serve	***
2		Erie	750	8	Miles	Line Rebuild	Erie	Obligation to serve	***
3		Union City	375	7.9	Miles	Line Rebuild	Union City	Obligation to serve	***
4		Nashville	1,250	12	Miles	Line Rebuild	Nashville	Obligation to serve	***
5		Dontz	250	1.3	Miles	Line Rebuild	Manistee	Obligation to serve	***
6		Sonoma	45	0.7	Miles	Line Rebuild	Battle Creek	Obligation to serve	***
7		Golden	75	0.5	Miles	Line Rebuild	Midland	Obligation to serve	***
8		Saranac	150	2.3	Miles	Line Rebuild	Saranac	Obligation to serve	***
9		Alden	1,900	8.2	Miles	Line Rebuild	Alden	Obligation to serve	***
10		Getty (Whole Line)	650	10.8	Miles	Pole Top Rehabilitation	Muskegon	Obligation to serve	***
11		Pole Replacements	1,423	100 (1185)	Poles	Pole Replacements	Various locations statewide	Obligation to serve	757,575
12		Switch Replacements	315	1	Switches	Switch Replacements	Various locations statewide	Obligation to serve	20,475
13		**LVD Asset Relocations Total**	**7,484**						

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	Reliability								
1	LVD Lines Reliability	RLBY Newburg Bancroft Voltage conv PHI	992	3	Miles	Voltage Conversion	BANCROFT	Customer-outage-minutes avoided	418,840
2		RLBY WURTSMITH_MISSION LCP 0057	429	1	Miles	Voltage Conversion	OSCODA	Customer-outage-minutes avoided	393,997
3		RLBY19 PRESCOTT_MAPLE RIDGE LCP 354	425	2	Miles	Voltage Conversion	PRESCOTT	Customer-outage-minutes avoided	1,369,230
4		McBain Voltage Conversion Part 1	1,000	106	Miles	Voltage Conversion	McBain	Customers	2196
5		RLBY PELLSTON_BURT LAKE LCP 233	390	0.86	Miles	Voltage Conversion	MUNRO	Customer-outage-minutes avoided	64218
6		EDMORE/CEDAR LAKE VOLT CONV	4,507	18.3	Miles	Voltage Conversion	MONTCALM	Customers	845
7		PEWAMO SUB VOLT CONVERSION IN FOWLER	1,040	4	Miles	Voltage Conversion	CLINTON	Customers	780
8		PEWAMO SUB VOLT CONVERSION M-21 REBUILD	1,775	0.9	Miles	Voltage Conversion	CLINTON	Customers	780
9		RLBY22 CHEBOYGAN-SEYMOUR LCP 250 SH-1	1,963	2.5	Miles	Voltage Conversion	CHEBOYGAN	Customer-outage-minutes avoided	45530
10		GRANT REHB19 8 POINT LUDINGTON LCP512 HZD	275	3	miles	Voltage Conversion	LAKE	Customer outage minutes avoided	18908
11		RLBY WURTSMITH_MISSION LCP 686 (part 1)	1,321	3.15	miles	Voltage Conversion	OSCODA	Customers	532
12		RLBY18 EIGHT POINT LUDINGTON LCP 547	268	4	miles	Voltage Conversion	LAKE	Customers	34
13		RLBY19 EIGHT PT LUDINGTON LCP 621	227	2	miles	Voltage Conversion	LAKE	Customer outage minutes avoided	15175
14		RLBY16 8 POINT_LUDINGTON LCP 9756	489	3	miles	Voltage Conversion	GARFIELD	Customer outage minutes avoided	163978
15		RLBY24 EIGHT POINT LK GRG LCP 321	406	7	miles	Voltage Conversion	FARWELL	Customer outage minutes avoided	59683
16		RLBY WURTSMITH_MISSION LCP 688 volt conv (part 3)	777	1.32	miles	Voltage Conversion	OSCODA	Customers	248
17		RLBY WURTSMITH_MISSION LCP 686 part 2	830	2.08	miles	Voltage Conversion	OSCODA	Customers	397
18		RLBY WURTSMITH_MISSION LCP 688 VConv 4	862	1.99	miles	Voltage Conversion	OSCODA	customers	218
19		RLBY WURTSMITH_MISSION LCP 187 volt conv (part 5)	421	0.85	miles	Voltage Conversion	OSCODA	customers	9
20		RLBY WURTSMITH_MISSION LCP 422 volt conv (part 6)	917	1.3	miles	Voltage Conversion	OSCODA	customers	21
21		RLBY Wurtsmith_Mission LCP 662	329	2.34	Miles	Voltage Conversion	Oscoda	Customer outage minutes avoided	40016
22		backus springbrook delta conversion	1,900	6	Miles	Voltage Conversion	DENTON	Customer outage minutes avoided	49673
23		RLBY Riverbend/Hale Rd Volt Conv Part 1	435	2.8	Miles	Voltage Conversion	Omer	Customers	111
24		RLBY Riverbend/Hale Rd Volt Conv Part 2	450	3.4	Miles	Voltage Conversion	Omer	Customers	27
25		RLBY Riverbend/Hale Rd Volt Conv Part 3	540	3.2	Miles	Voltage Conversion	Omer	Customers	51
26		RLBY Grayling_Bear LCP 087	270	2.71	Miles	Voltage Conversion	Grayling	Customer outage minutes avoided	9834
27		RLBY Turner/Gates LCP 450B Volt Conv	300	5.2	Miles	Voltage Conversion	Turner	Customers	3
28		RLBY Turner/Grove Volt Conv	60	0.16	Miles	Voltage Conversion	Turner	Customers	17
29		RLBY Au Gres/Point Look out Volt Conv	15	0.009	Miles	Voltage Conversion	Sims	Customers	1
30		RLBY Gilson_Wyman LCP 458 Volt Conv	273	14.16	Miles	Voltage Conversion	Rolland	Customer outage minutes avoided	38023
31		RLBY Gilson_Wyman LCP 608 Volt Conv	1,195	11.44	Miles	Voltage Conversion	Millbrook	Customers	221
32		RLBY Gilson_Wyman LCP 557 Volt Conv	70	0.66	Miles	Voltage Conversion	Rolland	Customers	22
33		RLBY Gilson_Wyman LCP 592 Volt Conv	281	2.58	Miles	Voltage Conversion	Home	Customer outage minutes avoided	17,502
34		RLBY Gilson_Rock Lake LCP 801 Volt Conv Part 1	1,560	6.79	Miles	Voltage Conversion	Home	Customers	218
35		RLBY Gilson_Rock Lake LCP 804 Volt Conv	27	0.11	Miles	Voltage Conversion	Home	Customers	2
36		RLBY NOBLE_WHITNEY LCP 521 Volt Conv	989	5.07	Miles	Voltage Conversion	SIMS	Customer outage minutes avoided	73885
37		RLBY19 NOBLE_WHITNEY LCP 563 VOLT CONV	615	2.91	Miles	Voltage Conversion	AU GRES	Customer outage minutes avoided	13124
38		RLBY Withey Lake/Pettit LCP 003 Volt Conv	727	5.44	Miles	Voltage Conversion	Logan	Customers	202
39		RLBY Withey Lake/Pettit LCP 006 Volt Conv	236	4.58	Miles	Voltage Conversion	Churchill	Customers	19
40		RLBY Withey Lake/Pettit LCP 706 Volt Conv	673	5.52	Miles	Voltage Conversion	Churchill	Customers	62
41		RLBY Tustin/WWTV LCP 221 Volt Conv	48	0.28	Miles	Voltage Conversion	Sherman	Customer	2
42		RLBY Scottville/Scottville LCP 656A Volt Conv	1,179	12.1	Miles	Voltage Conversion	Branch	Customer outage minutes avoided	5589
43		RLBY Scottville/US-31 LCP 223 Volt Conv	943	9.54	Miles	Voltage Conversion	Grant	Customer outage minutes avoided	1245
44		RLBY INDIAN RIVER/RONDO LCP 712 volt conv part 1	685	7.89	Miles	Voltage Conversion	Tuscarora	Customers	97
45		**LVD Lines Reliability Subtotal (Voltage Conversion Total)**	**33,115**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	VOLT 2421 Clyde Park Ave SW Low Voltage	42	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	3
2		VOLT MOLINE_MOLINE TLM 0412223102	50	0.2	Miles	Zonal Health Improvements	ALLEGAN	Service Quality; number of customers	13
3		VOLT BOWEN_KIMBERLY TLM 0611174201	56	0.16	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	15
4		VOLT 3268 Clyde Park Ave SW Low Voltage	31	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	17
5		VOLT MOLINE_MOLINE TLM 0412223101	52	0.25	Miles	Zonal Health Improvements	ALLEGAN	Service Quality; number of customers	18
6		VOLT PARKWAY_VINE 4404	34	0.15	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	18
7		VOLT BOWEN_KIMBERLY TLM 0611201102	52	0.21	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	19
8		VOLT PARKWAY_VINE 4403	29	0.17	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	23
9		VOLT RAMONA_BLODGETT TLM 0711332302	62	0.17	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	24
10		VOLT SKYLARK_SUN VALLEY LCP SUB	87	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	25
11		VOLT HARVEY_FULLER TLM 0711294410	57	0.2	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	26
12		VOLT BEALS RD_EXPRESSWAY TLM 0612234101	42	0.14	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	27
13		VOLT MONTROSE_MCKINLEY ROAD LCP SUB	43	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	30
14		RLBY BISHOP_RAINBOW LCP 061	25	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	33
15		VOLT BEALS RD_CLYDE PARK TLM 0612112106	81	0.1	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	37
16		VOLT MAYFAIR_PIERSON LCP SUB	61	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	40
17		VOLT Mayfair/Cass	90	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	41
18		VOLT 2424 McKee Ave SW Low Voltage	55	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	46
19		VOLT DoehlerJarvis_CottageGrove TLM 3105	101	0.3	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	46
20		VOLT PARKWAY_VINE 4101	30	0.15	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	55
21		VOLT KEARSLEY_COVERT ROAD LCP 793	61	6	Poles	Zonal Health Improvements	GENESEE	Service Quality; number of customers	62
22		VOLT PARKWAY_VINE 1408	70	0.78	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	76
23		VOLT LEITH STREET_WESTERN ROAD LCP 011	49	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	80
24		VOLT FOURTEENTH STREET_LIBERTY STREET	52	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	107
25		VOLT Rosebush_Stevenson Lk LCP 881	30	21.27	Miles	Zonal Health Improvements	ISABELLA	Service Quality; number of customers	162
26		VOLT STANLEY_SUMMIT LCP SUB	135	1	Project	Zonal Health Improvements	GENESEE	Service Quality; number of customers	170
27		RLBY19 SCENIC LK TIE TO LAINGSB LE PHIII	303	1.14	Miles	Zonal Health Improvements	SHIAWASSEE	Service Quality; number of customers	242
28		VOLT PLAINWELL_COMMERCIAL LCP 806	70	1	Poles	Zonal Health Improvements	ALLEGAN	Service Quality; number of customers	243
29		THDPY SHANTY CREEK_LODGE TIE LINE	291	0.42	Miles	Zonal Health Improvements	ANTRIM	Customers	278
30		GRID HARVEY_CORRECTION	61	1	Miles	Zonal Health Improvements	KENT	Service Quality; number of customers	528
31		GRID HAGER PARK01_HAGER PARK02	26	1	Project	Zonal Health Improvements	OTTAWA	Service Quality; number of customers	942
32		VOLT19 SUNFIELD-MULLIKEN--336	1,006	1.6	Miles	Zonal Health Improvements	EATON	Service Quality; number of customers	1032
33		FUSE23 MIDDLETON_GRANT	3	2	Fuses	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	1050
34		VOLT PHILLIPS ALCOTT 1202	30	0.15	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1341
35		VOLT PHILLIPS ALCOTT 2103 BURDICK	20	0.13	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1341
36		VOLT PHILLIPS ALCOTT 2105	50	0.24	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1341
37		VOLT PHILLIPS ALCOTT 2301	50	0.23	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1341
38		VOLT PHILLIPS ALCOTT 4303	45	0.11	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1341
39		VOLT PORTAGE MUSTANGS	190	1	Project	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1418
40		VOLT PORTAGE MUSTANGS 2303	26	0.08	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1418
41		ELSIE SUB UG EXIT	41	0.1	Miles	Zonal Health Improvements	CLINTON	Service Quality; number of customers	1490
42		SYSP Durand City Fusing	55	1	Project	Zonal Health Improvements	SHIAWASSEE	Service Quality; number of customers	1522
43		FUSE23 FOUR MILE_CORDES LCP 662_2	5	3	Fuses	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1575
44		FUSE23 GOGUAC_LAKEVIEW	4	3	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	1575
45		HZRD FRANKFORT-GATEWAY LCP 5554	42	0.58	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	1800
46		VOLT PARKWAY VINE 1401	70	0.13	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1971
47		VOLT PARKWAY VINE 4108_09	90	0.2	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	1971
48		HZRD18 KOLASSA_MATTESON LCP 706	130	1	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	2000
49		RLBY19 HOUGHTON HTS-PVL LCP 945	78	1	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	2027
50		GRID WEALTHY ST01_STANDALE01	61	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	2303
51		HZRD FRANKFORT-CRYSTALLIA LCP 9048	93	0.17	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	2352
52		GRID DIXIE01_MAYFAIR06	85	1	Project	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	3245
53		GRID HARVEY STREET_DIAMOND	74	1	Project	Zonal Health Improvements	KENT	Service Quality; number of customers	3488
54		FUSE23 PRESCOTT_LOGAN	16	8	Fuses	Zonal Health Improvements	OGEMAW	Customer-outage-minutes avoided	4200
55		FUSE23 MIDLAND_BUTTLES	12	9	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	4725
56		HZRD18 Behnke_Angola LCP 441	65	0.5	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	5800
57		FUSE23 BATTEESE_PLEASANT LAKE	16	12	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	6300
58		FUSE23 FLETCHER_ODEN	36	14	Fuses	Zonal Health Improvements	EMMET	Customer-outage-minutes avoided	7350
59		FUSE23 BATTEESE_COON HILL	21	16	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	8400
60		FUSE23 MT PLEASANT_COLLEGE	21	16	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	8400
61		FUSE23 BATTEESE_MUNITH	23	18	Fuses	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	9450
62		HZRD DONTZ RD-PORTAGE LCP 288	93	0.17	Miles	Zonal Health Improvements	MANISTEE	Customer-outage-minutes avoided	9492
63		RLBY CLARKSVILLE_MORRISON LAKE LCP 188	112	1	Project	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	10127
64		FUSE23 MIDDLETON_NEWARK	26	20	Fuses	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	10500
65		FUSE23 PINE RIVER_RURAL	26	20	Fuses	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	10500
66		RLBY16 MARKEY/FOREST ESTATES LCP 452	444	2	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	10796
67		VOLT_HOWARD CITY_MORLEY_LCP 040	30	3	Miles	Zonal Health Improvements	MONTCALM	Service Quality; number of customers	137
68		FUSE23 ASHMAN CIRCLE_ASHMAN	29	22	Fuses	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	11550
69		FUSE23 COMSTOCK_TUNIER	29	22	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	11550
70		FUSE23 COMSTOCK_SHIELDS	31	24	Fuses	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	12600
71		HZRD East Lake-Chemical 230	43	0.1	Miles	Zonal Health Improvements	MANISTEE	Customer-outage-minutes avoided	12953
72		SYSP19 HOMER_HOMER	3	2	Poles	Zonal Health Improvements	CALHOUN	System Protection Improvement; Customers	60
73		FUSE23 PRESCOTT_MAPLE RIDGE FUSE 20-26	61	26	Fuses	Zonal Health Improvements	OGEMAW	Customer-outage-minutes avoided	13650
74		HZRD Remus-Mecosta LCP 707	338	1.21	Miles	Zonal Health Improvements	MECOSTA	Customer-outage-minutes avoided	13920
75		RLBY Frankfort_Gateway LCP 5545	210	1.3	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	14182
76		FUSE23 MT PLEASANT_BROADWAY	39	30	Fuses	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	15750
77		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**6,198**						

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	Reliability								
1	LVD Lines Reliability	RLBY24 LYON MANOR TRSRE LCP 800	26	0.2	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	22141
2		FUSE23 DUCK LAKE_PARTELLO	57	44	Fuses	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	23100
3		FUSE23 KINDERHOOK_LAKE DRIVE	57	44	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	23100
4		VOLT_NINETEEN MILE RD_CEMENT_LCP 402	662	0.75	Miles	Zonal Health Improvements	MECOSTA	Service Quality; number of customers	158
5		RLBY DEWEY_SEATING LCP 210 1-14	872	0.75	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	24212
6		FUSE23 KINDERHOOK_GILEAD	62	48	Fuses	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	25200
7		SYSP19 CARLETON ROAD_BECK RD	10	7	Poles	Zonal Health Improvements	HILLSDALE	System Protection Improvement; Customers	214
8		FUSE23 LINCOLN_MIKADO Part 1	325	52	Fuses	Zonal Health Improvements	ALCONA	Customer-outage-minutes avoided	27300
9		RLBY NEELEY_HOOPER LCP 520	120	0.88	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	30731
10		VOLT SPRING DRIVE_BISHOP LAKE LCP sub	192	20	Poles	Zonal Health Improvements	NEWAYGO	Service Quality; number of customers	95
11		RLBY23 BACKUS SPRINGBROOK LCP 872	581	1.5	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	34604
12		FUSE23 GLADWIN_RURAL	86	66	Fuses	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	34650
13		FUSE23 FOREST GROVE_OTTOGAN	121	73	Fuses	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	38325
14		RLBY Foreman Vergennes LCP 673	296	0.57	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	39941
15		FUSE23 HOPKINS_MONTEREY PART 1	108	83	Fuses	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	43575
16		SAFETY21 TEKONSHA_TEKONSHA	150	0.3	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	44256
17		RLBY19 SPRING LAKE/COUNTRY CLUB LCP 416	147	0.35	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	44795
18		HZRD AUBIL LAKE TOWERS LCP SUB	150	0.6	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	45000
19		RLBY Camelot Lake Loomis LCP 182	215	0.75	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	47922
20		RLBY PeckRd_M91 LCP 453	210	1.2	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	56360
21		FUSE23 ROSE CITY_KLACKING CREEK	143	110	Fuses	Zonal Health Improvements	OGEMAW	Customer-outage-minutes avoided	57750
22		RLBY FISH LAKE_SEVEN LAKES LCP 0136	92	0.26	Miles	Zonal Health Improvements	OAKLAND	Customer-outage-minutes avoided	67397
23		GRID BROGAN01	15	1	Project	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	68760
24		RLBY Camelot Lake Loomis LCP 132	231	1	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	71438
25		RLBY GRANT GRANT LCP 620	919	3.33	Miles	Zonal Health Improvements	NEWAYGO	Customer-outage-minutes avoided	72635
26		GRANT RLBY HASKELITE_ANN STREET LCP CKT	45	0.4	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	76464
27		RLBY19 AUGUSTA-AUGUSTA LCP 596 Pt 1	431	1.13	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	77678
28		GRID - Princeton02_Pennfield01	35	1	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	79560
29		GRID Alder Creek02	21	1	Project	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	81600
30		GRID Fine Lake02	40	1	Project	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	81720
31		GRID CLARKSVILLE01_MORRISON LAKE01	45	1	Miles	Zonal Health Improvements	IONIA	Customer-outage-minutes avoided	82560
32		GRID Morgan02	60	1	Project	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	83760
33		VOLT PAVILION_DAVIS CREEK	380	0.9	Miles	Zonal Health Improvements	KALAMAZOO	Service Quality; number of customers	472
34		RLBY PECK ROAD_WISE ROAD LCP 535	231	0.9	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	94211
35		RLBY24 BACKUS SPRNGBRK LCP 466	759	2	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	95243
36		GRID COWAN LAKE02_HARVARD LAKE02	41	1	Project	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	95713
37		RLBY AU GRES_AU GRES LCP 661	415	2.075	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	98370
38		RLBY INGERSOLL_SASSE LCP 005	311	0.9	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	104830
39		GRID POTTERVILLE M78 3P GANG SW INST	43	1	Project	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	105107
40		RLBY GUN LAKE_TRAILS END LCP 552	420	0.67	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	108397
41		RLBY BROADWAY_PHILLIPS LCP 803	105	0.52	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	109899
42		RLBY BRETON_TOWERS LCP SUB	180	0.13	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	110000
43		GRID SALEM01	30	1	Project	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	111480
44		GRANT RLBY CRYSTAL_CRYSTAL RD 468 1-??	1,109	1.5	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	113656
45		GRID COWAN LAKE01_RATIGAN01	25	1	Poles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	114524
46		RLBY BITTERSWEET RIVER ROAD LCP 753	300	0.8	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	115096
47		CC RLBY14 HULL STREET--LIME LAKE LCP-805	175	0.33	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	118324
48		GRID - Cranbrook02_Convis03	13	1	Project	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	120600
49		GRID COWAN LAKE02_BRICKER01	12	1	Project	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	123588
50		RLBY TWILIGHT_GULL ROAD LCP 474	450	0.6	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	124441
51		RLBY MULLINS_ROYAL VISTA LCP 312	148	0.1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	124749
52		RLBY18 Alder Creek - E Leroy LCP 614	546	3.8	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	131744
53		RLBY OSHTEMO_HURD LCP 242	650	1.25	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	131934
54		CC RLBY15 HULL STREET--LIME LAKE LCP-814	309	0.78	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	135801
55		GRID MILL GROVE01_MILL GROVE_03	30	1	Project	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	142320
56		RLBY Bella Vista/Blakely LCP-545 PART 1	825	2	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	143229
57		REHAB17 HOLTON MAPLE ISLAND FAILING WIRE	193	0.57	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	152109
58		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**14,224**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	RLBY AUBIL LAKE_TOWERS LCP 886	220	0.43	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	166593
2		RLBY15 DIMONDALE-DIMONDALE PH1	1,172	2.5	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	170025
3		GRID ALGER01_ALGER02	210	1	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	170679
4		GRANT RLBY RANGER LAKE_GOODAR LCP 158	305	2.07	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	172633
5		GRID HASTINGS01_RUTLAND02	70	1	Project	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	172920
6		GRID TEKONSHA01_HOMER01	30	1	Project	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	199320
7		RLBY COWAN LAKE/RAMSDELL Tree Wire	542	1.19	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	207906
8		RLBY BEADLE_SPAULDING LCP 329	400	0.65	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	227178
9		RLBY Cedar Springs-White Creek LCP 810	410	0.9	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	234815
10		RLBY PIGEON LAKE-OLIVE SUB ZONE	350	0.7	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	236000
11		RLBY18 RYNO_MAPES SUB PART 1A	1,547	3.75	Miles	Zonal Health Improvements	OSCODA	Customer-outage-minutes avoided	237191
12		RLBY Cowan Lake_Ramsdell LCP 829	266	0.64	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	240000
13		RLBY Honor_Platte LCP 0107	165	0.5	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	254211
14		GRID SUMMIT FOURTH ST_INGHAM GREENWOOD	50	1	Project	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	270000
15		GRID RIDGEVIEW01_GALESBURG01	30	1	Project	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	282960
16		GRID WEALTHY ST01_WEALTHY08	128	6	Poles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	289680
17		RLBY CONKLIN PARK_CROTON LCP 946	641	1.54	Miles	Zonal Health Improvements	NEWAYGO	Customer-outage-minutes avoided	290633
18		RLBY18 HOWARD CITY/CORAL SPLIT CKT	360	0.16	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	309731
19		GRANT WLDFRE RYNO-MAPES LCP 244	1,337	3.48	Miles	Zonal Health Improvements	OSCODA	Customer-outage-minutes avoided	311485
20		GRANT RLBY Knapp/Perkins LCP 86	315	1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	313000
21		RLBY RANGER LAKE_KOKOSING 556	120	10	Poles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	318756
22		RLBY15 BATTEESE/MUNITH (Previously RPOUT	329	0.8	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	329460
23		REHAB15 INGHAM/THIRD UNDERGROUND EXIT RE	22	0.1	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	365051
24		GRID - CONVIS02_FIFTEEN MILE02	60	1	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	382080
25		RLBY LARKIN_EASTMAN LCP SUB	324	0.86	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	393124
26		RLBY18 Honor/Platte LCP 0076	346	1.9	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	408279
27		GRANT RLBY Alden_Clam LCP 7009	102	0.18	Miles	Zonal Health Improvements	ANTRIM	Customer-outage-minutes avoided	408676
28		GRID SAUGATUCK 03_NEW RICHMOND01	30	1	Project	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	428880
29		TIE16LAKE LEANN/LAKE LEANN-WALDRON RD	55	0.57	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	436567
30		RLBY Ramona/Reeds Lake TW Backbone Recon	400	0.4	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	477600
31		RLBY HANOVER/PULASKI-STRAIT RD	280	1	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	567501
32		GRID KENTWOOD02_KENTWOOD04	78	1	Project	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	572160
33		RLBY22 Brooklyn_Ford N Main St Michigan	70	0.1	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	636860
34		RLBY Batteese_Coon_Hill_LCP_0978	501	0.85	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	640000
35		HZRD PENINSULA-MAPLETON CARROLL RD	110	0.86	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	689783
36		RLBY CONKLIN PARK_CROTON LCP 971	1,125	1.4	Miles	Zonal Health Improvements	NEWAYGO	Customer-outage-minutes avoided	715919
37		RLBY18 GREGORY UNADILLA LCP 934	927	1.5	Miles	Zonal Health Improvements	LIVINGSTON	Customer-outage-minutes avoided	822358
38		RLBY17 MARTIN_SHELBYVILLE SUB	186	0.25	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	829659
39		GRID WARNER01_WARNER02	30	1	Project	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	1034460
40		RLBY21NAPOLEON-STONEY LK-NAPOLEON RD	205	0.71	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	1037546
41		RLBY17 HANOVER/PULASKI LCP532 Folks Rd A	349	1.61	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	1636272
42		RLBY PRICE ROAD_MERIDIAN LCP 0513	298	0.72	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	2873044
43		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**14,496**						
44		**Zonal Health Total**	**34,917**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	SCDY College Park/Madison	1,620	5.4	Miles	Secondary	ADRIAN	Service Quality; number of customers	1,167
2		SCDY Liberty/Washington	300	1.0	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	599
3		SCDY Phillips/Milwood	2,040	6.8	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	1,055
4		SCDY Sloan/Longfellow	2,490	8.3	Miles	Secondary	FLINT	Service Quality; number of customers	820
5		SCDY Eastwood/Texel	300	1.0	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	140
6		SCDY Summit/Fourth	2,100	7.0	Miles	Secondary	JACKSON	Service Quality; number of customers	952
7		SCDY Lombard/Sheridan	1,800	6.0	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	688
8		SCDY Elm Street/Porter	270	0.9	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	1,430
9		SCDY Elm Street/Verona	300	1.0	Miles	Secondary	BATTLE CREEK	Service Quality; number of customers	125
10		SCDY Augusta/Augusta	540	1.8	Miles	Secondary	KALAMAZOO	Service Quality; number of customers	276
11		SCDY Fourteenth Street/South Western	360	1.2	Miles	Secondary	FLINT	Service Quality; number of customers	562
12		SCDY Wayland/Wayland	450	1.5	Miles	Secondary	HAMILTON	Service Quality; number of customers	202
13		SCDY Oriole/Whittier	1,590	5.3	Miles	Secondary	LUDINGTON	Service Quality; number of customers	612
14		SCDY Derby/Derby	330	1.1	Miles	Secondary	GREENVILLE	Service Quality; number of customers	139
15		SCDY Lake Leann/Bundy Hill	180	0.6	Miles	Secondary	JACKSON	Service Quality; number of customers	70
16		**LVD Lines Reliability Subtotal (Secondary Total)**	**14,670**						
17		UINJ Cable Rejuvenation Flint	28,871	69	Miles	Underground Cable Injection	Flint Area	Customer-outage-minutes avoided	1589997
18		UINJ Cable Rejuvenation Grand Rapids	15,647	37	Miles	Underground Cable Injection	Grand Rapids Area	Customer-outage-minutes avoided	861719
19		UINJ Cable Rejuvenation Traverse City	21,471	52	Miles	Underground Cable Injection	Traverse City Area	Customer-outage-minutes avoided	1182461
20		**LVD Lines Reliability Subtotal (Underground Cable Injection Total)**	**65,989**						
21		**Right of Way**	**17,667**	n/a	n/a	Right of Way			n/a
22		**Groundline Inspections - Pole Replacements**	**127,500**	12,500	Poles	Pole Replacements	Statewide	Customer-outage-minutes avoided	32359
23		**LVD Lines Reliability Subtotal**	**306,485**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	EXIT JACKMAN SUB 1-6 & 3-6	21	1	Project	Circuit Exit Projects	Jackson	Increase Safety by Installing Isolation Point	0
2		EXIT PHILLIPS	22	1	Project	Circuit Exit Projects	Kalamazoo	Increase Safety by Installing Isolation Point	0
3		Exit Red Arrow	11	1	Project	Circuit Exit Projects	Flint	Increase Safety by Installing Isolation Point	0
4		EXIT RANKIN-ALL CKTS	17	1	Project	Circuit Exit Projects	Rankin	Increase Safety by Installing Isolation Point	0
5		RLBY Rivertown Sub Exit SW	88	1	Project	Circuit Exit Projects	Grandville	Increase Safety by Installing Isolation Point	0
6		EXIT ROBERTS STREET	32	1	Project	Circuit Exit Projects	Jackson	Increase Safety by Installing Isolation Point	0
7		EXIT VANDERCOOK LAKE	24	1	Project	Circuit Exit Projects	Jackson	Increase Safety by Installing Isolation Point	0
8		EXIT ST HELEN SUB EXIT SWITCHES	20	1	Project	Circuit Exit Projects	St Helen	Increase Safety by Installing Isolation Point	0
9		RLBY Plainfield Sub Exit SW	33	1	Project	Circuit Exit Projects	Plainfield	Increase Safety by Installing Isolation Point	0
10		EXIT DIMONDALE	16	1	Project	Circuit Exit Projects	Dimondale	Increase Safety by Installing Isolation Point	0
11		EXIT PARNALL	16	1	Project	Circuit Exit Projects	Jackson	Increase Safety by Installing Isolation Point	0
12		RLBY Lamoreaux Sub Exit SW	24	1	Project	Circuit Exit Projects	Grand Rapids	Increase Safety by Installing Isolation Point	0
13		EXIT POTTERVILLE	16	1	Project	Circuit Exit Projects	Potterville	Increase Safety by Installing Isolation Point	0
14		EXIT LOMBARD	26	1	Project	Circuit Exit Projects	Albion	Increase Safety by Installing Isolation Point	0
15		EXIT PARKWAY	11	1	Project	Circuit Exit Projects	Kalamazoo	Increase Safety by Installing Isolation Point	0
16		EXIT OAKWOOD	17	1	Project	Circuit Exit Projects	Kalamazoo	Increase Safety by Installing Isolation Point	0
17		EXIT KINGSLEY SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	Kingsley	Increase Safety by Installing Isolation Point	0
18		EXIT KELLOGGSVILLE/CHEMICAL CKTS 34	18	1	Project	Circuit Exit Projects	Grand Rapids	Increase Safety by Installing Isolation Point	0
19		EXIT Ottawa Beach Sub	15	1	Project	Circuit Exit Projects	Holland	Increase Safety by Installing Isolation Point	0
20		EXIT MCBAIN SUB EXIT SWITCHES	17	1	Project	Circuit Exit Projects	McBain	Increase Safety by Installing Isolation Point	0
21		EXIT ROSCOMMON SUB EXIT SWITCHES	13	1	Project	Circuit Exit Projects	Roscommon	Increase Safety by Installing Isolation Point	0
22		RLBY Cowan Lake Sub Exit SW	22	1	Project	Circuit Exit Projects	Cannon	Increase Safety by Installing Isolation Point	0
23		EXIT LAKE MITCHELL SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	Cadillac	Increase Safety by Installing Isolation Point	0
24		EXIT GLENDALE	18	1	Project	Circuit Exit Projects	Kalamazoo	Increase Safety by Installing Isolation Point	0
25		EXIT BEECHER	29	1	Project	Circuit Exit Projects	Adrian	Increase Safety by Installing Isolation Point	0
26		Exit Antrim Sub Exit Switches	16	1	Project	Circuit Exit Projects	Elk Rapids	Increase Safety by Installing Isolation Point	0
27		EXIT MANTON SUB EXIT SWITCHES	33	1	Project	Circuit Exit Projects	Manton	Increase Safety by Installing Isolation Point	0
28		EXIT MENDON	26	1	Project	Circuit Exit Projects	Mendon	Increase Safety by Installing Isolation Point	0
29		EXIT STANDISH_STANDISH	9	1	Project	Circuit Exit Projects	Standish	Increase Safety by Installing Isolation Point	0
30		EXIT TEXAS	29	1	Project	Circuit Exit Projects	Kalamazoo	Increase Safety by Installing Isolation Point	0
31		EXIT TUSTIN SUB EXIT SWITCHES	19	1	Project	Circuit Exit Projects	Tustin	Increase Safety by Installing Isolation Point	0
32		Exit PELLSTON SUB - EXIT SWITCHES	16	1	Project	Circuit Exit Projects	Pellston	Increase Safety by Installing Isolation Point	0
33		EXIT MANITOU BEACH	16	1	Project	Circuit Exit Projects	Addison	Increase Safety by Installing Isolation Point	0
34		EXIT DUNBAR SUB	21	1	Project	Circuit Exit Projects	Monroe	Increase Safety by Installing Isolation Point	0
35		EXIT BELLEVUE	32	1	Project	Circuit Exit Projects	Bellevue	Increase Safety by Installing Isolation Point	0
36		EXIT BALDWIN SUB SUB EXIT SWITCHES	26	1	Project	Circuit Exit Projects	Baldwin	Increase Safety by Installing Isolation Point	0
37		EXIT FREELAND/FREELAND	10	1	Project	Circuit Exit Projects	Freeland	Increase Safety by Installing Isolation Point	0
38		RLBY Alto Sub Exit SW	7	1	Project	Circuit Exit Projects	Lowell	Increase Safety by Installing Isolation Point	0
39		EXIT MESICK SUB EXIT SWITCHES	13	1	Project	Circuit Exit Projects	Mesick	Increase Safety by Installing Isolation Point	0
40		RLBY Foreman Sub Exit SW	7	1	Project	Circuit Exit Projects	Lowell	Increase Safety by Installing Isolation Point	0
41		EXIT HOSPITAL SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	Traverse City	Increase Safety by Installing Isolation Point	0
42		RLBY Meadowbrooke Sub Exit SW	22	1	Project	Circuit Exit Projects	Grand Rapids	Increase Safety by Installing Isolation Point	0
43		RLBY Kraft Avenue Sub Exit SW	17	1	Project	Circuit Exit Projects	Grand Rapids	Increase Safety by Installing Isolation Point	0
44		EXIT HOMER	15	1	Project	Circuit Exit Projects	Homer	Increase Safety by Installing Isolation Point	0
45		Exit MANCELONA SUB - EXIT SWITCHES	16	1	Project	Circuit Exit Projects	Mancelona	Increase Safety by Installing Isolation Point	0
46		EXIT TAWAS_TAWAS	25	1	Project	Circuit Exit Projects	Tawas City	Increase Safety by Installing Isolation Point	0
47		EXIT OLIVET	26	1	Project	Circuit Exit Projects	Olivet	Increase Safety by Installing Isolation Point	0
48		EXIT ESSEXVILLE_ESSEXVILLE	9	1	Project	Circuit Exit Projects	Essexville	Increase Safety by Installing Isolation Point	0
49		EXIT LELAND SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	Lake Leelanau	Increase Safety by Installing Isolation Point	0
50		EXIT FERRIS STREET SUB EXIT SW	19	1	Project	Circuit Exit Projects	Grand Haven	Increase Safety by Installing Isolation Point	0
51		EXIT THOMAS/FROST	10	1	Project	Circuit Exit Projects	Saginaw	Increase Safety by Installing Isolation Point	0
52		EXIT STOCKBRIDGE	21	1	Project	Circuit Exit Projects	Stockbridge	Increase Safety by Installing Isolation Point	0
53		EXIT SALZBURG_SALZBURG	9	1	Project	Circuit Exit Projects	Bay City	Increase Safety by Installing Isolation Point	0
54		EXIT KNIGHT_HAMPTON	9	1	Project	Circuit Exit Projects	Bay City	Increase Safety by Installing Isolation Point	0
55		RLBY Marne Sub Exit SW	44	1	Project	Circuit Exit Projects	Coopersville	Increase Safety by Installing Isolation Point	0
56		EXIT TEKONSHA	15	1	Project	Circuit Exit Projects	Tekonsha	Increase Safety by Installing Isolation Point	0
57		EXIT SHATTUCK/COUNTY FARM	10	1	Project	Circuit Exit Projects	Saginaw	Increase Safety by Installing Isolation Point	0
58		EXIT SURREY_SURREY	9	1	Project	Circuit Exit Projects	Farwell	Increase Safety by Installing Isolation Point	0
59		EXIT OSCODA_BUTLER HEIGHTS	9	1	Project	Circuit Exit Projects	Oscoda	Increase Safety by Installing Isolation Point	0
60		EXIT WOODWARD SUB EXIT SWITCHES	13	1	Project	Circuit Exit Projects	Selma	Increase Safety by Installing Isolation Point	0
61		**LVD Lines Reliability Subtotal (Circuit Exits Subtotal)**	**1,163**						

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	Reliability								
1	LVD Lines Reliability	RLBY Pettis Road Sub Exit SW	7	1	Project	Circuit Exit Projects	ADA	Increase Safety by Installing Isolation Point	0
2		REHAB20 AUBURN_AUBURN UG EXIT	250	1	Project	Circuit Exit Projects	WILLIAMS	Increase Safety by Installing Isolation Point	0
3		EXIT FREELAND/RURAL	20	1	Project	Circuit Exit Projects	TITTABAWASSEE	Increase Safety by Installing Isolation Point	0
4		EXIT Ensley Sub	16	1	Project	Circuit Exit Projects	SAND LAKE	Increase Safety by Installing Isolation Point	0
5		EXIT SPRINGPORT	16	1	Project	Circuit Exit Projects	SPRINGPORT	Increase Safety by Installing Isolation Point	0
6		EXIT READING	15	1	Project	Circuit Exit Projects	READING	Increase Safety by Installing Isolation Point	0
7		WISNER UG EXIT	20	1	Project	Circuit Exit Projects	BLACKMAN	Increase Safety by Installing Isolation Point	0
8		EXIT BIL-MAR	46	1	Project	Circuit Exit Projects	OLIVE	Increase Safety by Installing Isolation Point	0
9		EXIT LITCHFIELD	15	1	Project	Circuit Exit Projects	LITCHFIELD	Increase Safety by Installing Isolation Point	0
10		EXIT JANES/BELAIR	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
11		EXIT SMALLWOOD DAM_WOODEN SHOE	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	0
12		EXIT KAWKAWLIN_LAGOON BEACH	9	1	Project	Circuit Exit Projects	KAWKAWLIN	Increase Safety by Installing Isolation Point	0
13		EXIT CHEYENNE_GREEN ACRES	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
14		EXIT CAMDEN	15	1	Project	Circuit Exit Projects	CAMDEN	Increase Safety by Installing Isolation Point	0
15		EXIT BARNARD/WEISS	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
16		EXIT LASALLE SUB	24	1	Project	Circuit Exit Projects	LASALLE	Increase Safety by Installing Isolation Point	0
17		EXIT WESTERVELT/TITTABAWASSEE	10	1	Project	Circuit Exit Projects	ZILWAUKEE	Increase Safety by Installing Isolation Point	0
18		EXIT ASHMAN CIRCLE_HIGH SCHOOL	9	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	0
19		RLBY Alpine Sub Exit SW	33	1	Project	Circuit Exit Projects	ALPINE	Increase Safety by Installing Isolation Point	0
20		EXIT PINCONNING_WHITE FEATHER	9	1	Project	Circuit Exit Projects	PINCONNING	Increase Safety by Installing Isolation Point	0
21		EXIT RIVERDALE_RIVERDALE	9	1	Project	Circuit Exit Projects	SUMNER	Increase Safety by Installing Isolation Point	0
22		EXIT BEHNKE	13	1	Project	Circuit Exit Projects	COLDWATER	Increase Safety by Installing Isolation Point	0
23		EXIT CHESANING/CHESANING	20	1	Project	Circuit Exit Projects	CHESANING	Increase Safety by Installing Isolation Point	0
24		EXIT CHEYENNE_ MCDONALDS	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
25		RLBY North Park Sub Exit SW	22	1	Project	Circuit Exit Projects	GRAND RAPIDS	Increase Safety by Installing Isolation Point	0
26		EXIT HARVEY STREET/FULLER CKT 6	9	1	Project	Circuit Exit Projects	GRAND RAPIDS	Increase Safety by Installing Isolation Point	0
27		RLBY Mullins Sub Exit SW	66	1	Project	Circuit Exit Projects	WALKER	Increase Safety by Installing Isolation Point	0
28		EXIT PORTSMOUTH/BLUMFIELD	10	1	Project	Circuit Exit Projects	BLUMFIELD	Increase Safety by Installing Isolation Point	0
29		EXIT SHATTUCK/CENTER ROAD	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
30		RLBY Godfrey Sub Exit SW	7	1	Project	Circuit Exit Projects	VERGENNES	Increase Safety by Installing Isolation Point	0
31		EXIT SUTTONS BAY SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	SUTTONS BAY	Increase Safety by Installing Isolation Point	0
32		RLBY Ratigan Sub Exit SW	22	1	Project	Circuit Exit Projects	CANNON	Increase Safety by Installing Isolation Point	0
33		EXIT BRISTOL/MILLER	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
34		Exit BELLAIRE SUB - EXIT SWITCHES	16	1	Project	Circuit Exit Projects	BELLAIRE	Increase Safety by Installing Isolation Point	0
35		EXIT BOWEN/AIRCRAFT CKTS 12	18	1	Project	Circuit Exit Projects	GRAND RAPIDS	Increase Safety by Installing Isolation Point	0
36		EXIT ULMER/BURT ROAD	10	1	Project	Circuit Exit Projects	BIRCH RUN	Increase Safety by Installing Isolation Point	0
37		EXIT ROUND LAKE	16	1	Project	Circuit Exit Projects	WOODSTOCK	Increase Safety by Installing Isolation Point	0
38		EXITS BROGAN	19	1	Project	Circuit Exit Projects	HASTINGS	Increase Safety by Installing Isolation Point	0
39		EXIT ST CHARLES/FERGUS	20	1	Project	Circuit Exit Projects	SAINT CHARLES	Increase Safety by Installing Isolation Point	0
40		EXIT BOON ROAD SUB EXIT SWITCHES	8	1	Project	Circuit Exit Projects	HARING	Increase Safety by Installing Isolation Point	0
41		EXIT GREENBUSH_GREENBUSH	9	1	Project	Circuit Exit Projects	HARRISVILLE	Increase Safety by Installing Isolation Point	0
42		EXIT KNIGHT_FARLEY	9	1	Project	Circuit Exit Projects	HAMPTON	Increase Safety by Installing Isolation Point	0
43		EXIT Harlem Sub	40	1	Project	Circuit Exit Projects	OLIVE	Increase Safety by Installing Isolation Point	0
44		EXIT RIVERDALE_SUMNER	9	1	Project	Circuit Exit Projects	SUMNER	Increase Safety by Installing Isolation Point	0
45		EXIT MCGRAW_PORTSMOUTH	10	1	Project	Circuit Exit Projects	PORTSMOUTH	Increase Safety by Installing Isolation Point	0
46		EXIT MIDDLETON_MIDDLETON	9	1	Project	Circuit Exit Projects	FULTON	Increase Safety by Installing Isolation Point	0
47		EXIT MT FOREST_BENTLEY	9	1	Project	Circuit Exit Projects	MOUNT FOREST	Increase Safety by Installing Isolation Point	0
48		EXIT PORTSMOUTH/INDIANTOWN	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
49		EXIT BRISTOL/BRISTOL	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
50		EXIT DUQUITE_PINE RIVER	25	1	Project	Circuit Exit Projects	STANDISH	Increase Safety by Installing Isolation Point	0
51		EXIT UG VILLAGE GREEN CKT 1 EXIT A	11	1	Project	Circuit Exit Projects	PORTAGE	Increase Safety by Installing Isolation Point	0
52		EXIT BARNARD/HOSPITAL	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
53		EXIT NIAGARA/ADAMS	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
54		EXIT NIAGARA_HAMILTON	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
55		RLBY Palo Sub Exit SW	7	1	Project	Circuit Exit Projects	RONALD	Increase Safety by Installing Isolation Point	0
56		EXIT GLADWIN_BUZZELL	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	0
57		EXIT BILLWOOD	8	1	Project	Circuit Exit Projects	WINDSOR	Increase Safety by Installing Isolation Point	0
58		EXIT EDMORE_SIX LAKES	9	1	Project	Circuit Exit Projects	EDMORE	Increase Safety by Installing Isolation Point	0
59		EXIT WOOD STREET SUB	9	1	Project	Circuit Exit Projects	FLINT	Increase Safety by Installing Isolation Point	0
60		EXIT WURTSMITH_MISSION	9	1	Project	Circuit Exit Projects	OSCODA	Increase Safety by Installing Isolation Point	0
61		EXIT FRANKENMUTH/MAIN STREET	10	1	Project	Circuit Exit Projects	FRANKENMUTH	Increase Safety by Installing Isolation Point	0
62		EXIT JANES/JANES	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
63		EXIT FRANKENMUTH/DEHMEL	10	1	Project	Circuit Exit Projects	FRANKENMUTH	Increase Safety by Installing Isolation Point	0
64		REHAB18 Elsie Sub Exits	21	1	Project	Circuit Exit Projects	MERRILL	Increase Safety by Installing Isolation Point	0
65		EXIT MERRILL_CHAPIN	9	1	Project	Circuit Exit Projects	MERRILL	Increase Safety by Installing Isolation Point	0
66		**LVD Lines Reliability Subtotal (Circuit Exits Subtotal)**	**1,239**						

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Test Year LVD Project List

For the Test Year 12 Months Ending April 30, 2027

($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 9 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	EXIT ROSEBUSH_DELWIN	9	1	Project	Circuit Exit Projects	ISABELLA	Increase Safety by Installing Isolation Point	0
2		EXIT GREENBUSH_HARRISVILLE	9	1	Project	Circuit Exit Projects	HARRISVILLE	Increase Safety by Installing Isolation Point	0
3		EXIT EDMORE_CEDAR LAKE	9	1	Project	Circuit Exit Projects	EDMORE	Increase Safety by Installing Isolation Point	0
4		EXITS WOODLAND	19	1	Project	Circuit Exit Projects	WOODLAND	Increase Safety by Installing Isolation Point	0
5		EXIT INTERLOCHEN SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	INTERLOCHEN	Increase Safety by Installing Isolation Point	0
6		EXITS RUTLAND	19	1	Project	Circuit Exit Projects	HASTINGS	Increase Safety by Installing Isolation Point	0
7		EXIT CHEYENNE_LAWNDALE	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
8		EXIT JANES/WALNUT	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
9		EXIT BARNARD/BARNARD	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
10		EXIT CHESANING/PEET	10	1	Project	Circuit Exit Projects	CHESANING	Increase Safety by Installing Isolation Point	0
11		EXIT TOWN LINE_MACKINAW	9	1	Project	Circuit Exit Projects	MONITOR	Increase Safety by Installing Isolation Point	0
12		EXIT CHESANING/OAKLEY	20	1	Project	Circuit Exit Projects	CHESANING	Increase Safety by Installing Isolation Point	0
13		EXIT HARING SUB EXIT SWITCHES	21	1	Project	Circuit Exit Projects	CADILLAC	Increase Safety by Installing Isolation Point	0
14		EXIT SOUTH WASHINGTON/FORDNEY	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
15		EXIT MIDDLETON_NEWARK	9	1	Project	Circuit Exit Projects	FULTON	Increase Safety by Installing Isolation Point	0
16		EXIT SMALLWOOD DAM_DISTRIBUTION	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	0
17		EXIT MERRILL_MERRILL	9	1	Project	Circuit Exit Projects	MERRILL	Increase Safety by Installing Isolation Point	0
18		EXIT HURON_TWO MILE	9	1	Project	Circuit Exit Projects	BAY CITY	Increase Safety by Installing Isolation Point	0
19		EXIT COGGINS_NEWBERG	9	1	Project	Circuit Exit Projects	FRASER	Increase Safety by Installing Isolation Point	0
20		EXIT DUQUITE_SAGANING	20	1	Project	Circuit Exit Projects	STANDISH	Increase Safety by Installing Isolation Point	0
21		EXIT ROSEBUSH_STEVENSON LAKE	9	1	Project	Circuit Exit Projects	ISABELLA	Increase Safety by Installing Isolation Point	0
22		EXIT BARNARD/BAYSIDE	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
23		EXIT HURON_MONITOR	9	1	Project	Circuit Exit Projects	BAY CITY	Increase Safety by Installing Isolation Point	0
24		EXIT 0-AT-KA SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	TRAVERSE CITY	Increase Safety by Installing Isolation Point	0
25		EXIT KOCHVILLE/SCHUST	10	1	Project	Circuit Exit Projects	KOCHVILLE	Increase Safety by Installing Isolation Point	0
26		EXIT CARROLLTON/MAPLE RIDGE	10	1	Project	Circuit Exit Projects	CARROLLTON	Increase Safety by Installing Isolation Point	0
27		EXIT ESSEXVILLE_WOODSIDE	9	1	Project	Circuit Exit Projects	HAMPTON	Increase Safety by Installing Isolation Point	0
28		EXIT KOCHVILLE_KRAENZLEIN	10	1	Project	Circuit Exit Projects	KOCHVILLE	Increase Safety by Installing Isolation Point	0
29		EXIT SWAN CREEK SUB	15	1	Project	Circuit Exit Projects	CHESHIRE	Increase Safety by Installing Isolation Point	0
30		EXIT EAST BAY SUB EXIT SWITCHES	20	1	Project	Circuit Exit Projects	TRAVERSE CITY	Increase Safety by Installing Isolation Point	0
31		EXIT PINCONNING_PINCONNING	9	1	Project	Circuit Exit Projects	PINCONNING	Increase Safety by Installing Isolation Point	0
32		EXIT GLADWIN_SPRING	9	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	0
33		EXIT MT FOREST_MT FOREST	9	1	Project	Circuit Exit Projects	MOUNT FOREST	Increase Safety by Installing Isolation Point	0
34		EXIT HALEY ROAD	13	1	Project	Circuit Exit Projects	SENECA	Increase Safety by Installing Isolation Point	0
35		EXIT INGERSOLL_SASSE	9	1	Project	Circuit Exit Projects	INGERSOLL	Increase Safety by Installing Isolation Point	0
36		RLBY Coit Avenue Sub Exit SW	33	1	Project	Circuit Exit Projects	PLAINFIELD	Increase Safety by Installing Isolation Point	0
37		EXIT MORLEY/HOLLAND	10	1	Project	Circuit Exit Projects	BUENA VISTA	Increase Safety by Installing Isolation Point	0
38		EXIT FRANKENMUTH/INDUSTRIAL	10	1	Project	Circuit Exit Projects	FRANKENMUTH	Increase Safety by Installing Isolation Point	0
39		EXIT EAST GRANT SUB EXIT SW	12	1	Project	Circuit Exit Projects	GRANT	Increase Safety by Installing Isolation Point	0
40		EXIT EDGEWOOD_DISTRIBUTION	9	1	Project	Circuit Exit Projects	LAFAYETTE	Increase Safety by Installing Isolation Point	0
41		EXIT CARROLLTON/CARROLLTON	20	1	Project	Circuit Exit Projects	CARROLLTON	Increase Safety by Installing Isolation Point	0
42		EXIT HOTCHKISS_BAY VALLEY	22	1	Project	Circuit Exit Projects	MONITOR	Increase Safety by Installing Isolation Point	0
43		EXIT WINGATE	16	1	Project	Circuit Exit Projects	SHARON	Increase Safety by Installing Isolation Point	0
44		EXIT DUQUITE_JOHNSFIELD	20	1	Project	Circuit Exit Projects	STANDISH	Increase Safety by Installing Isolation Point	0
45		Exit DIETZ ROAD Sub Exit Switches	16	1	Project	Circuit Exit Projects	BOYNE FALLS	Increase Safety by Installing Isolation Point	0
46		EXIT LEELANAU SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	OMENA	Increase Safety by Installing Isolation Point	0
47		EXIT ESSEXVILLE_CENTER ROAD	9	1	Project	Circuit Exit Projects	HAMPTON	Increase Safety by Installing Isolation Point	0
48		EXIT KOCHVILLE/PIERCE	10	1	Project	Circuit Exit Projects	KOCHVILLE	Increase Safety by Installing Isolation Point	0
49		EXIT INGERSOLL_LAPORTE	9	1	Project	Circuit Exit Projects	INGERSOLL	Increase Safety by Installing Isolation Point	0
50		EXIT SPRINKLE	50	1	Project	Circuit Exit Projects	PORTAGE	Increase Safety by Installing Isolation Point	0
51		EXIT TOWN LINE_FRASER	9	1	Project	Circuit Exit Projects	MONITOR	Increase Safety by Installing Isolation Point	0
52		EXIT JASPER_REDSTONE	9	1	Project	Circuit Exit Projects	JASPER	Increase Safety by Installing Isolation Point	0
53		EXIT EDDY/FINDLEY	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
54		EXIT HART DISTRIBUTION SUB EXIT SW	9	1	Project	Circuit Exit Projects	HART	Increase Safety by Installing Isolation Point	0
55		EXIT JASPER_JASPER	9	1	Project	Circuit Exit Projects	JASPER	Increase Safety by Installing Isolation Point	0
56		RLBY - WILDER WILDER 15KV SUB EXIT	340	1	Project	Circuit Exit Projects	ECKFORD	Increase Safety by Installing Isolation Point	0
57		EXIT LOVELL	3	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	0
58		EXIT WATERTOWN	8	1	Project	Circuit Exit Projects	WATERTOWN	Increase Safety by Installing Isolation Point	0
59		EXIT KAWKAWLIN_RUSSELL	9	1	Project	Circuit Exit Projects	KAWKAWLIN	Increase Safety by Installing Isolation Point	0
60		EXIT PATTERSON_STATE	9	1	Project	Circuit Exit Projects	BAY CITY	Increase Safety by Installing Isolation Point	0
61		EXIT MIDDLETON_GRANT	9	1	Project	Circuit Exit Projects	FULTON	Increase Safety by Installing Isolation Point	0
62		EXIT MCGRAW_CASS	10	1	Project	Circuit Exit Projects	PORTSMOUTH	Increase Safety by Installing Isolation Point	0
63		EXIT SOUTH WASHINGTON/HOYT STREET	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
64		EXIT COGGINS_ALMEDA	9	1	Project	Circuit Exit Projects	FRASER	Increase Safety by Installing Isolation Point	0
65		EXIT SHERMAN_SHERMAN	9	1	Project	Circuit Exit Projects	WILBER	Increase Safety by Installing Isolation Point	0
66		EXIT MAYNARD	14	1	Project	Circuit Exit Projects	WALKER	Increase Safety by Installing Isolation Point	0
67		EXIT AU GRES_POINT LOOK-OUT	9	1	Project	Circuit Exit Projects	SIMS	Increase Safety by Installing Isolation Point	0
68		EXIT FRANKENMUTH/GERA	10	1	Project	Circuit Exit Projects	FRANKENMUTH	Increase Safety by Installing Isolation Point	0
69		Exits Renton	7	1	Project	Circuit Exit Projects	BATTLE CREEK	Increase Safety by Installing Isolation Point	0
70		EXIT KOCHVILLE/CARDINALS	10	1	Project	Circuit Exit Projects	KOCHVILLE	Increase Safety by Installing Isolation Point	0
71		EXIT EDDY/WADSWORTH	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
72		EXIT SOUTH WASHINGTON/GALLAGHER	20	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	0
73		**LVD Lines Reliability Subtotal (Circuit Exits Subtotal)**	**1,214**						
74		**Circuit Exits Total**	**3,616**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 10 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliabiity	GRANT DISTA WILMOTT01_OTSEGO01	692	1	Loop	Automation - ATR Loops	Allegan	Customer-outage-minutes-avoided	251,904
2		GRANT DISTA GREENSPIRE01_KALARAMA01	367	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	90,288
3		DISTA BLINTON03_BLINTON02_UPGRADE	367	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	433,872
4		GRANT DISTA TECUMSEH01_HENDERSHOT01	367	1	Loop	Automation - ATR Loops	Lenawee	Customer-outage-minutes-avoided	106,992
5		GRANT DISTA GREENWOOD02_GREENWOOD01	694	1	Loop	Automation - ATR Loops	Ogemaw	Customer-outage-minutes-avoided	525,936
6		GRANT DISTA HOGSBACK01_HOGSBACK03	494	1	Loop	Automation - ATR Loops	Ingham	Customer-outage-minutes-avoided	37,392
7		GRANT DISTA COMSTOCK01_RIDGEVIEW02	429	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	86,400
8		GRANT DISTA LARKIN04_ASHMAN CIRCLE02	469	1	Loop	Automation - ATR Loops	Midland	Customer-outage-minutes-avoided	70,512
9		GRANT DISTA PARMA01_MAINS ROAD02	469	1	Loop	Automation - ATR Loops	Jackson	Customer-outage-minutes-avoided	116,496
10		GRANT DISTA SPRING DR02_BUTTERFIELD02	367	1	Loop	Automation - ATR Loops	Newaygo	Customer-outage-minutes-avoided	164,256
11		GRANT DISTA LEVEL PARK02_SPRINGFIELD04	561	1	Loop	Automation - ATR Loops	Calhoun	Customer-outage-minutes-avoided	127,824
12		GRANT DISTA GLENDALE02_TRAVIS02	367	1	Loop	Automation - ATR Loops	Kalamazoo	Customer-outage-minutes-avoided	92,736
13		GRANT DISTA TEKONSHA01_HOMER01	840	1	Loop	Automation - ATR Loops	Calhoun	Customer-outage-minutes-avoided	96,000
14		GRANT DISTA MANCHESTER03_WINGATE01	592	1	Loop	Automation - ATR Loops	Washtenaw	Customer-outage-minutes-avoided	60,480
15		GRANT DISTA MURNER01_BAGLEY03	367	1	Loop	Automation - ATR Loops	Otsego	Customer-outage-minutes-avoided	110,592
16		GRANT DISTA EIGHT POINT03_SURREY01	369	1	Loop	Automation - ATR Loops	Clare	Customer-outage-minutes-avoided	91,584
17		GRANT DISTA LEVEL PARK02_BEDFORD02	581	1	Loop	Automation - ATR Loops	Calhoun	Customer-outage-minutes-avoided	101,376
18		GRANT DISTA FRUITPORT01_ELLIS01	933	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	252,528
19		DISTA MICHIGAN CTR02_EAST JACKSON02	571	1	Loop	Automation - ATR Loops	Jackson	Customer-outage-minutes-avoided	156,672
20		GRANT DISTA BAGLEY01_MURNER02	245	1	Loop	Automation - ATR Loops	Otsego	Customer-outage-minutes-avoided	349,248
21		GRANT DISTA CADMUS01_BEECHER02	367	1	Loop	Automation - ATR Loops	Lenawee	Customer-outage-minutes-avoided	130,512
22		GRANT DISTA CADMUS02_CADMUS01	367	1	Loop	Automation - ATR Loops	Lenawee	Customer-outage-minutes-avoided	51,120
23		GRANT DISTA BRIDGEPORT01_ALABAMA02	367	1	Loop	Automation - ATR Loops	Saginaw	Customer-outage-minutes-avoided	58,560
24		GRANT DISTA LAKE MITCHELL02_CADILLAC03	672	1	Loop	Automation - ATR Loops	Wexford	Customer-outage-minutes-avoided	54,528
25		GRANT DISTA KOLASSA01_BURR OAK01	367	1	Loop	Automation - ATR Loops	Branch	Customer-outage-minutes-avoided	43,872
26		DISTA MAYFAIR06_STANLEY02_UPGRADE	367	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	105,888
27		GRANT DISTA DIMONDALE01_DIMONDALE02	457	1	Loop	Automation - ATR Loops	Eaton	Customer-outage-minutes-avoided	108,960
28		GRANT DISTA CENTER ROAD02_BELSAY01	367	1	Loop	Automation - ATR Loops	Genesee	Customer-outage-minutes-avoided	173,376
29		GRANT DISTA BURROWS02_BURROWS01	367	1	Loop	Automation - ATR Loops	Saginaw	Customer-outage-minutes-avoided	31,104
30		GRANT DISTA MUSKEGON HEIGHTS03_KEATING01	367	1	Loop	Automation - ATR Loops	Muskegon	Customer-outage-minutes-avoided	111,072
31		GRANT DISTA ROBERTS STREET03_EAST JACKSON01	245	1	Loop	Automation - ATR Loops	Jackson	Customer-outage-minutes-avoided	24,336
32		GRANT DISTA STURGEON03_LARKIN01	490	1	Loop	Automation - ATR Loops	Midland	Customer-outage-minutes-avoided	58,704
33		GRANT DISTA GRAND LEDGE04_GRAND LEDGE03	469	1	Loop	Automation - ATR Loops	Eaton	Customer-outage-minutes-avoided	112,656
34		**LVD Lines Reliability Subtotal (ATR Loop Total)**	**15,412**						
35		**LVD Lines Reliability Total**	**312,886**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT CENTREVILLE-BUSINESS LCP 422	90	1	Project	Repetitive Outage Projects	CENTREVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	57,318
2	LVD Repetitive Outages	RPOUT ALCONA DAM-GLENNIE LCP 932	90	1	Project	Repetitive Outage Projects	CURTIS	Reduce Repeated Outages; Customer-outage-minutes avoided	34,946
3	LVD Repetitive Outages	RPOUT SMALLWOOD DAM-DISTRIBUTION LCP 874	90	1	Project	Repetitive Outage Projects	BUCKEYE	Reduce Repeated Outages; Customer-outage-minutes avoided	21,197
4	LVD Repetitive Outages	RPOUT CONVIS-WALNUT POINT LCP 238	90	1	Project	Repetitive Outage Projects	MARSHALL	Reduce Repeated Outages; Customer-outage-minutes avoided	15,812
5	LVD Repetitive Outages	RPOUT MENDON-M-60 LCP 728	90	1	Project	Repetitive Outage Projects	MENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	7,906
6	LVD Repetitive Outages	RPOUT HOMER-INDUSTRIAL LCP 650	90	1	Project	Repetitive Outage Projects	HOMER	Reduce Repeated Outages; Customer-outage-minutes avoided	48,196
7	LVD Repetitive Outages	RPOUT LINCOLN-MIKADO LCP 806	90	1	Project	Repetitive Outage Projects	GREENBUSH	Reduce Repeated Outages; Customer-outage-minutes avoided	20,975
8	LVD Repetitive Outages	RPOUT COMSTOCK-SHIELDS LCP 675	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	161,003
9	LVD Repetitive Outages	RPOUT DIMONDALE-ROSSMAN LCP 339	90	1	Project	Repetitive Outage Projects	DIMONDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	42,773
10	LVD Repetitive Outages	RPOUT RAVENNA-MOORLAND LCP 177	90	1	Project	Repetitive Outage Projects	RAVENNA	Reduce Repeated Outages; Customer-outage-minutes avoided	29,954
11	LVD Repetitive Outages	RPOUT HOUGHTON HEIGHTS-PRUDENVILLE LCP 945	90	1	Project	Repetitive Outage Projects	DENTON	Reduce Repeated Outages; Customer-outage-minutes avoided	80,346
12	LVD Repetitive Outages	RPOUT SYLVAN-RURAL LCP 405	90	1	Project	Repetitive Outage Projects	CHELSEA	Reduce Repeated Outages; Customer-outage-minutes avoided	41,938
13	LVD Repetitive Outages	RPOUT FOUR MILE-BAUMHOFF LCP CKT	90	1	Project	Repetitive Outage Projects	WALKER	Reduce Repeated Outages; Customer-outage-minutes avoided	97,514
14	LVD Repetitive Outages	RPOUT MT FOREST-MT FOREST LCP 599	90	1	Project	Repetitive Outage Projects	LINCOLN	Reduce Repeated Outages; Customer-outage-minutes avoided	62,757
15	LVD Repetitive Outages	RPOUT BELDING-COOKS CORNERS LCP 233	90	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	22,557
16	LVD Repetitive Outages	RPOUT MACATAWA-WENDT PARK LCP 715	90	1	Project	Repetitive Outage Projects	HOLLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	51,921
17	LVD Repetitive Outages	RPOUT TEXAS-BASS LAKE LCP 656	90	1	Project	Repetitive Outage Projects	TEXAS	Reduce Repeated Outages; Customer-outage-minutes avoided	53,223
18	LVD Repetitive Outages	RPOUT BEHNKE-RIVER RD LCP 697	90	1	Project	Repetitive Outage Projects	COLDWATER	Reduce Repeated Outages; Customer-outage-minutes avoided	6,826
19	LVD Repetitive Outages	RPOUT BEDFORD-MEACHEM LCP 623	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	54,238
20	LVD Repetitive Outages	RPOUT KOLASSA-KOSMERICK LCP 154	90	1	Project	Repetitive Outage Projects	BRONSON	Reduce Repeated Outages; Customer-outage-minutes avoided	7,264
21	LVD Repetitive Outages	RPOUT BAGLEY-OTSEGO LAKE LCP 5544	90	1	Project	Repetitive Outage Projects	GAYLORD	Reduce Repeated Outages; Customer-outage-minutes avoided	213,230
22	LVD Repetitive Outages	RPOUT COGGINS-NEWBERG LCP 197	90	1	Project	Repetitive Outage Projects	FRASER	Reduce Repeated Outages; Customer-outage-minutes avoided	66,770
23	LVD Repetitive Outages	RPOUT ELLIS-DANGL LCP 228	90	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	47,589
24	LVD Repetitive Outages	RPOUT DRAKE ROAD-PRAIRIES GOLF LCP CKT	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	9,224
25	LVD Repetitive Outages	RPOUT TUCKER-MACKEY LCP 657	90	1	Project	Repetitive Outage Projects	HOLLY	Reduce Repeated Outages; Customer-outage-minutes avoided	35,879
26	LVD Repetitive Outages	RPOUT CEDAR LAKE-KINGS CORNER LCP 541	90	1	Project	Repetitive Outage Projects	GREENBUSH	Reduce Repeated Outages; Customer-outage-minutes avoided	91,811
27	LVD Repetitive Outages	RPOUT UPTON-MT HOPE LCP 724	90	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	100,646
28	LVD Repetitive Outages	RPOUT RANGER LAKE-GOODAR LCP 185	90	1	Project	Repetitive Outage Projects	MENTOR	Reduce Repeated Outages; Customer-outage-minutes avoided	252,691
29	LVD Repetitive Outages	RPOUT WHITTEMORE-M-65 LCP 855	90	1	Project	Repetitive Outage Projects	WHITTEMORE	Reduce Repeated Outages; Customer-outage-minutes avoided	49,615
30	LVD Repetitive Outages	RPOUT COTTAGE GROVE-PREVO LCP 428	90	1	Project	Repetitive Outage Projects	KAWKAWLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	9,992
31	LVD Repetitive Outages	RPOUT WATKINS-CHRISTY LCP 491	90	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	61,288
32	LVD Repetitive Outages	RPOUT ALDER CREEK-LEE LAKE LCP 390	90	1	Project	Repetitive Outage Projects	UNION CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	58,648
33	LVD Repetitive Outages	RPOUT SANDERSON-M-57 LCP 171	90	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	24,433
34	LVD Repetitive Outages	RPOUT SANDERSON-M-57 LCP 799	90	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	35,697
35	LVD Repetitive Outages	RPOUT MILL GROVE-BABYLON LCP 155	90	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	103,649
36	LVD Repetitive Outages	RPOUT BACKUS-SPRINGBROOK LCP 507	90	1	Project	Repetitive Outage Projects	DENTON	Reduce Repeated Outages; Customer-outage-minutes avoided	14,881
37	LVD Repetitive Outages	RPOUT DORR CORNERS-RED RUN LCP 149	90	1	Project	Repetitive Outage Projects	DORR	Reduce Repeated Outages; Customer-outage-minutes avoided	11,386
38	LVD Repetitive Outages	RPOUT HILL ROAD-PINE WAY LCP 267	90	1	Project	Repetitive Outage Projects	MUNDY	Reduce Repeated Outages; Customer-outage-minutes avoided	48,761
39	LVD Repetitive Outages	RPOUT BLUE STAR-PIER COVE LCP 622	90	1	Project	Repetitive Outage Projects	SAUGATUCK	Reduce Repeated Outages; Customer-outage-minutes avoided	22,702
40	LVD Repetitive Outages	RPOUT ASH ROAD-STERLING ROAD LCP 135	90	1	Project	Repetitive Outage Projects	LITCHFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	32,854
41	LVD Repetitive Outages	RPOUT ASH ROAD-STERLING ROAD LCP 230	90	1	Project	Repetitive Outage Projects	LITCHFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	29,412
42	LVD Repetitive Outages	RPOUT MILTON-MAPLE ST LCP 179	90	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	30,696
43	LVD Repetitive Outages	RPOUT ALCONA DAM-CURTISVILLE LCP 773	90	1	Project	Repetitive Outage Projects	MENTOR	Reduce Repeated Outages; Customer-outage-minutes avoided	94,184
44	LVD Repetitive Outages	RPOUT EVANSTON-EVANSTON LCP 221	90	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	12,081
45	LVD Repetitive Outages	RPOUT PULLMAN-CHICORA LCP 21	90	1	Project	Repetitive Outage Projects	CLYDE	Reduce Repeated Outages; Customer-outage-minutes avoided	28,347
46	LVD Repetitive Outages	RPOUT WILDWOOD-YARDMAN LCP 991	90	1	Project	Repetitive Outage Projects	BLACKMAN	Reduce Repeated Outages; Customer-outage-minutes avoided	9,025
47	LVD Repetitive Outages	RPOUT MENDON-PINHOOK LCP 909	90	1	Project	Repetitive Outage Projects	MENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	22,669
48	LVD Repetitive Outages	RPOUT AUSTIN-LONG LAKE LCP 819	90	1	Project	Repetitive Outage Projects	PORTAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	30,431
49	LVD Repetitive Outages	RPOUT ONEKAMA-CHIEF LCP 736	90	1	Project	Repetitive Outage Projects	BEAR LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	3,240
50	LVD Repetitive Outages	RPOUT GRANT-GRANT LCP 361	90	1	Project	Repetitive Outage Projects	GRANT	Reduce Repeated Outages; Customer-outage-minutes avoided	13,925
		LVD Repetitive Outages Subtotal	**4,500**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT SARANAC-RIVERSIDE LCP 989	90	1	Project	Repetitive Outage Projects	SARANAC	Reduce Repeated Outages; Customer-outage-minutes avoided	37,840
2	LVD Repetitive Outages	RPOUT CEDAR SPRINGS-EDGERTON LCP 361	90	1	Project	Repetitive Outage Projects	CEDAR SPRINGS	Reduce Repeated Outages; Customer-outage-minutes avoided	8,920
3	LVD Repetitive Outages	RPOUT SUNFIELD-SUNFIELD LCP 842	90	1	Project	Repetitive Outage Projects	SUNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	24,738
4	LVD Repetitive Outages	RPOUT HARRISON-DODGE CITY LCP 221	90	1	Project	Repetitive Outage Projects	HARRISON	Reduce Repeated Outages; Customer-outage-minutes avoided	34,642
5	LVD Repetitive Outages	RPOUT HULL STREET-CRANBERRY LCP 608	90	1	Project	Repetitive Outage Projects	SPARTA	Reduce Repeated Outages; Customer-outage-minutes avoided	5,367
6	LVD Repetitive Outages	RPOUT APPLE-CHATTERSON ROAD LCP 385	90	1	Project	Repetitive Outage Projects	EGELSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	23,410
7	LVD Repetitive Outages	RPOUT APPLE-CHATTERSON ROAD LCP 605	90	1	Project	Repetitive Outage Projects	EGELSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	8,682
8	LVD Repetitive Outages	RPOUT CAMDEN-CAMDEN LCP 148	90	1	Project	Repetitive Outage Projects	CAMDEN	Reduce Repeated Outages; Customer-outage-minutes avoided	55,616
9	LVD Repetitive Outages	RPOUT HESPERIA-RURAL LCP 970	90	1	Project	Repetitive Outage Projects	SHERMAN	Reduce Repeated Outages; Customer-outage-minutes avoided	11,022
10	LVD Repetitive Outages	RPOUT GODFREY-LOWELL LCP 451	90	1	Project	Repetitive Outage Projects	KEENE	Reduce Repeated Outages; Customer-outage-minutes avoided	1,828
11	LVD Repetitive Outages	RPOUT MERSON-MERSON LCP 559	90	1	Project	Repetitive Outage Projects	GOBLES	Reduce Repeated Outages; Customer-outage-minutes avoided	41,967
12	LVD Repetitive Outages	RPOUT GALESBURG-CHARLESTON LCP 473	90	1	Project	Repetitive Outage Projects	GALESBURG	Reduce Repeated Outages; Customer-outage-minutes avoided	24,516
13	LVD Repetitive Outages	RPOUT CONCORD-SWAINS LAKE LCP 537	90	1	Project	Repetitive Outage Projects	CONCORD	Reduce Repeated Outages; Customer-outage-minutes avoided	29,878
14	LVD Repetitive Outages	RPOUT RODNEY-RODNEY LCP 195	90	1	Project	Repetitive Outage Projects	COLFAX	Reduce Repeated Outages; Customer-outage-minutes avoided	6,959
15	LVD Repetitive Outages	RPOUT MORGAN-ST MARYS LCP 386	90	1	Project	Repetitive Outage Projects	PENNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	14,787
16	LVD Repetitive Outages	RPOUT FENNVILLE-COMMERCIAL LCP 941	90	1	Project	Repetitive Outage Projects	FENNVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	53,421
17	LVD Repetitive Outages	RPOUT BELDING-MALL LCP 251	90	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	13,335
18	LVD Repetitive Outages	RPOUT BELDING-COOKS CORNERS LCP 826	90	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	16,812
19	LVD Repetitive Outages	RPOUT LETTS ROAD-MONROE ROAD LCP 552	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	48,108
20	LVD Repetitive Outages	RPOUT NESTROM-SCENIC DRIVE LCP 494	90	1	Project	Repetitive Outage Projects	LAKETON	Reduce Repeated Outages; Customer-outage-minutes avoided	24,396
21	LVD Repetitive Outages	RPOUT MOLINE-CHAPPEL LCP 431	90	1	Project	Repetitive Outage Projects	BYRON	Reduce Repeated Outages; Customer-outage-minutes avoided	4,803
22	LVD Repetitive Outages	RPOUT EAST LAKE-PINE CREEK LCP 373	90	1	Project	Repetitive Outage Projects	EASTLAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	97,375
23	LVD Repetitive Outages	RPOUT POTTERVILLE-M-78 LCP 573	90	1	Project	Repetitive Outage Projects	POTTERVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	34,802
24	LVD Repetitive Outages	RPOUT CHICAGO-PINEBROOK LCP 489	90	1	Project	Repetitive Outage Projects	HUDSONVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	4,321
25	LVD Repetitive Outages	RPOUT ATHENS-SHERWOOD LCP 227	90	1	Project	Repetitive Outage Projects	ATHENS	Reduce Repeated Outages; Customer-outage-minutes avoided	62,161
26	LVD Repetitive Outages	RPOUT KENDALL-WESTWOOD LCP 750	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	16,390
27	LVD Repetitive Outages	RPOUT RIVERDALE-RIVERDALE LCP 28	90	1	Project	Repetitive Outage Projects	SEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	48,764
28	LVD Repetitive Outages	RPOUT SCOTTS-WHITE LCP 240	90	1	Project	Repetitive Outage Projects	CHARLESTON	Reduce Repeated Outages; Customer-outage-minutes avoided	4,649
29	LVD Repetitive Outages	RPOUT LEHRING-COLE ROAD LCP 735	90	1	Project	Repetitive Outage Projects	BYRON	Reduce Repeated Outages; Customer-outage-minutes avoided	15,073
30	LVD Repetitive Outages	RPOUT MACATAWA-WENDT PARK LCP 740	90	1	Project	Repetitive Outage Projects	HOLLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	25,006
31	LVD Repetitive Outages	RPOUT DEAN ROAD-SHANNON LAKE LCP 135	90	1	Project	Repetitive Outage Projects	ARGENTINE	Reduce Repeated Outages; Customer-outage-minutes avoided	90,593
32	LVD Repetitive Outages	RPOUT MAGNUS-EAGLE CORNER LCP 835	90	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoided	24,054
33	LVD Repetitive Outages	RPOUT KEATING-WOOD STREET LCP 309	90	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	2,462
34	LVD Repetitive Outages	RPOUT FIFTEEN MILE ROAD-A DRIVE LCP 104	90	1	Project	Repetitive Outage Projects	MARSHALL	Reduce Repeated Outages; Customer-outage-minutes avoided	6,908
35	LVD Repetitive Outages	RPOUT BURTCH ROAD-WELCH LAKE LCP 308	90	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	109,927
36	LVD Repetitive Outages	RPOUT BURTCH ROAD-WELCH LAKE LCP CKT	90	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	29,993
37	LVD Repetitive Outages	RPOUT DERBY-DERBY LCP 213	90	1	Project	Repetitive Outage Projects	DOUGLASS	Reduce Repeated Outages; Customer-outage-minutes avoided	26,922
38	LVD Repetitive Outages	RPOUT BOON ROAD-ROUND LAKE LCP 556	90	1	Project	Repetitive Outage Projects	HARING	Reduce Repeated Outages; Customer-outage-minutes avoided	40,273
39	LVD Repetitive Outages	RPOUT GILSON-WYMAN LCP 460	90	1	Project	Repetitive Outage Projects	EDMORE	Reduce Repeated Outages; Customer-outage-minutes avoided	12,439
40	LVD Repetitive Outages	RPOUT OBERLIN-BENMARK LCP 337	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	147,368
41	LVD Repetitive Outages	RPOUT OBERLIN-BENMARK LCP 707	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	6,255
42	LVD Repetitive Outages	RPOUT OBERLIN-BENMARK LCP 850	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	11,505
43	LVD Repetitive Outages	RPOUT ABBE-ABBE LCP 28	90	1	Project	Repetitive Outage Projects	MENTOR	Reduce Repeated Outages; Customer-outage-minutes avoided	134,450
44	LVD Repetitive Outages	RPOUT BILLWOOD-BILLWOOD LCP CKT	90	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	122,704
45	LVD Repetitive Outages	RPOUT CRAWFORD-WINN LCP 192	90	1	Project	Repetitive Outage Projects	UNION	Reduce Repeated Outages; Customer-outage-minutes avoided	27,618
46	LVD Repetitive Outages	RPOUT KRAFT AVENUE-TAHOE LCP 254	90	1	Project	Repetitive Outage Projects	CASCADE	Reduce Repeated Outages; Customer-outage-minutes avoided	12,045
47	LVD Repetitive Outages	RPOUT FOREMAN-CUMBERLAND LCP 357	90	1	Project	Repetitive Outage Projects	ADA	Reduce Repeated Outages; Customer-outage-minutes avoided	49,268
48	LVD Repetitive Outages	RPOUT KIPP ROAD-M-36 LCP 39	90	1	Project	Repetitive Outage Projects	MASON	Reduce Repeated Outages; Customer-outage-minutes avoided	42,524
49	LVD Repetitive Outages	RPOUT BENNINGTON-GRAND RIVER LCP 517	90	1	Project	Repetitive Outage Projects	LAINGSBURG	Reduce Repeated Outages; Customer-outage-minutes avoided	24,607
50	LVD Repetitive Outages	RPOUT BENNINGTON-GRAND RIVER LCP 575	90	1	Project	Repetitive Outage Projects	LAINGSBURG	Reduce Repeated Outages; Customer-outage-minutes avoided	60,948
51		**LVD Repetitive Outages Subtotal**	**4,500**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 13 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT ALGER-SKIDWAY LCP 940	90	1	Project	Repetitive Outage Projects	RICHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	22,331
2	LVD Repetitive Outages	RPOUT RICHLAND-THREE LAKES LCP 515	90	1	Project	Repetitive Outage Projects	RICHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	25,731
3	LVD Repetitive Outages	RPOUT MAINES ROAD-WELLMAN ROAD LCP 113	90	1	Project	Repetitive Outage Projects	SANDSTONE	Reduce Repeated Outages; Customer-outage-minutes avoided	25,899
4	LVD Repetitive Outages	RPOUT FISH LAKE-ROSE LCP 30	90	1	Project	Repetitive Outage Projects	HOLLY	Reduce Repeated Outages; Customer-outage-minutes avoided	104,811
5	LVD Repetitive Outages	RPOUT BEAVERTON-ROSS STREET LCP 346	90	1	Project	Repetitive Outage Projects	BEAVERTON	Reduce Repeated Outages; Customer-outage-minutes avoided	9,177
6	LVD Repetitive Outages	RPOUT QUINCY-BLACKHAWK LCP 876	90	1	Project	Repetitive Outage Projects	COLDWATER	Reduce Repeated Outages; Customer-outage-minutes avoided	80,100
7	LVD Repetitive Outages	RPOUT LINDEN-LOBDELL LCP 635	90	1	Project	Repetitive Outage Projects	LINDEN	Reduce Repeated Outages; Customer-outage-minutes avoided	43,987
8	LVD Repetitive Outages	RPOUT LEELANAU-OMENA BAY LCP 323	90	1	Project	Repetitive Outage Projects	LEELANAU	Reduce Repeated Outages; Customer-outage-minutes avoided	27,161
9	LVD Repetitive Outages	RPOUT EVANSTON-EVANSTON LCP 255	90	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	70,737
10	LVD Repetitive Outages	RPOUT TWELFTH STREET-WESTFIELD LCP 84	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	128,482
11	LVD Repetitive Outages	RPOUT WESTERN AVENUE-LAKESIDE LCP 232	90	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	82,559
12	LVD Repetitive Outages	RPOUT PHILLIPS-MILWOOD LCP 659	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	45,490
13	LVD Repetitive Outages	RPOUT MONTROSE-VOLKMER LCP 173	90	1	Project	Repetitive Outage Projects	MONTROSE	Reduce Repeated Outages; Customer-outage-minutes avoided	8,122
14	LVD Repetitive Outages	RPOUT NORTH MUSKEGON-DALTON LCP 279	90	1	Project	Repetitive Outage Projects	N MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	6,949
15	LVD Repetitive Outages	RPOUT CHESTER-MORRELL LCP 242	90	1	Project	Repetitive Outage Projects	CARMEL	Reduce Repeated Outages; Customer-outage-minutes avoided	61,337
16	LVD Repetitive Outages	RPOUT CONKLIN PARK-HOLLY LCP 930	90	1	Project	Repetitive Outage Projects	REYNOLDS	Reduce Repeated Outages; Customer-outage-minutes avoided	13,667
17	LVD Repetitive Outages	RPOUT OTISVILLE-IRISH ROAD LCP 998	90	1	Project	Repetitive Outage Projects	OTISVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,666
18	LVD Repetitive Outages	RPOUT HOMER-INDUSTRIAL LCP 637	90	1	Project	Repetitive Outage Projects	HOMER	Reduce Repeated Outages; Customer-outage-minutes avoided	38,451
19	LVD Repetitive Outages	RPOUT LAMBERTVILLE-SUMMERFIELD LCP 260	90	1	Project	Repetitive Outage Projects	BEDFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	16,096
20	LVD Repetitive Outages	RPOUT COMSTOCK-SHIELDS LCP 655	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	5,796
21	LVD Repetitive Outages	RPOUT HULL STREET-CRANBERRY LCP 486	90	1	Project	Repetitive Outage Projects	SPARTA	Reduce Repeated Outages; Customer-outage-minutes avoided	18,432
22	LVD Repetitive Outages	RPOUT KNIGHT-ROSEMARY LCP 931	90	1	Project	Repetitive Outage Projects	BAY CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	14,422
23	LVD Repetitive Outages	RPOUT BATTEESE-PLEASANT LAKE LCP 9162	90	1	Project	Repetitive Outage Projects	LESLIE	Reduce Repeated Outages; Customer-outage-minutes avoided	35,859
24	LVD Repetitive Outages	RPOUT MORRELL-MCCAIN LCP 825	90	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	14,619
25	LVD Repetitive Outages	RPOUT GRASS LAKE-GRASS LAKE LCP 148	90	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	25,435
26	LVD Repetitive Outages	RPOUT CONCORD-SWAINS LAKE LCP 524	90	1	Project	Repetitive Outage Projects	CONCORD	Reduce Repeated Outages; Customer-outage-minutes avoided	14,903
27	LVD Repetitive Outages	RPOUT LAKE LEANN-LAKE LEANN LCP 199	90	1	Project	Repetitive Outage Projects	SOMERSET	Reduce Repeated Outages; Customer-outage-minutes avoided	48,206
28	LVD Repetitive Outages	RPOUT GERRISH-LEGION LCP 278	90	1	Project	Repetitive Outage Projects	GRAYLING	Reduce Repeated Outages; Customer-outage-minutes avoided	12,639
29	LVD Repetitive Outages	RPOUT MONTAGUE-NORTH SHORE LCP 443	90	1	Project	Repetitive Outage Projects	MONTAGUE	Reduce Repeated Outages; Customer-outage-minutes avoided	62,110
30	LVD Repetitive Outages	RPOUT CRYSTAL-MT HOPE ROAD LCP 793	90	1	Project	Repetitive Outage Projects	CRYSTAL	Reduce Repeated Outages; Customer-outage-minutes avoided	52,486
31	LVD Repetitive Outages	RPOUT BELDING-COOKS CORNERS LCP 219	90	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	33,558
32	LVD Repetitive Outages	RPOUT PRESCOTT-MAPLE RIDGE LCP 373	90	1	Project	Repetitive Outage Projects	PRESCOTT	Reduce Repeated Outages; Customer-outage-minutes avoided	26,666
33	LVD Repetitive Outages	RPOUT MT MORRIS-WOOLFIT LCP 479	90	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	13,959
34	LVD Repetitive Outages	RPOUT DAVISON-CONTINENTAL LCP 311	90	1	Project	Repetitive Outage Projects	DAVISON	Reduce Repeated Outages; Customer-outage-minutes avoided	37,994
35	LVD Repetitive Outages	RPOUT POTTERVILLE-POTTERVILLE LCP 103	90	1	Project	Repetitive Outage Projects	POTTERVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	72,251
36	LVD Repetitive Outages	RPOUT ENGLISHVILLE-PINE ISLAND LCP 381	90	1	Project	Repetitive Outage Projects	PLAINFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	8,384
37	LVD Repetitive Outages	RPOUT BREEDSVILLE-GRAND JUNCTION LCP 956	90	1	Project	Repetitive Outage Projects	COLUMBIA	Reduce Repeated Outages; Customer-outage-minutes avoided	6,422
38	LVD Repetitive Outages	RPOUT SCOTTS-SCOTTS LCP 578	90	1	Project	Repetitive Outage Projects	WAKESHMA	Reduce Repeated Outages; Customer-outage-minutes avoided	35,022
39	LVD Repetitive Outages	RPOUT HOPKINS-HOPKINS LCP 753	90	1	Project	Repetitive Outage Projects	HOPKINS	Reduce Repeated Outages; Customer-outage-minutes avoided	7,087
40	LVD Repetitive Outages	RPOUT LAKE CITY-JENNINGS LCP 630	90	1	Project	Repetitive Outage Projects	LAKE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	16,611
41	LVD Repetitive Outages	RPOUT MAYFAIR-MAYFAIR LCP 409	90	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	25,196
42	LVD Repetitive Outages	RPOUT TRAVIS-COLLINGWOOD LCP 600	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	2,100
43	LVD Repetitive Outages	RPOUT ENSLEY-DISTRIBUTION LCP 694	90	1	Project	Repetitive Outage Projects	ENSLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	18,077
44	LVD Repetitive Outages	RPOUT HONOR-PLATTE LCP 144	90	1	Project	Repetitive Outage Projects	HONOR	Reduce Repeated Outages; Customer-outage-minutes avoided	17,193
45	LVD Repetitive Outages	RPOUT EASTLAWN-FLAJOLE LCP 298	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	7,212
46	LVD Repetitive Outages	RPOUT OVID-OVID LCP 379	90	1	Project	Repetitive Outage Projects	OVID	Reduce Repeated Outages; Customer-outage-minutes avoided	35,157
47	LVD Repetitive Outages	RPOUT SQUIRE HILL-EDGEWATER LCP 353	90	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	19,775
48	LVD Repetitive Outages	RPOUT OBERLIN-BENMARK LCP 763	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	39,898
49	LVD Repetitive Outages	RPOUT OBERLIN-BENMARK LCP 764	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	20,704
50	LVD Repetitive Outages	RPOUT ABBE-ABBE LCP 417	90	1	Project	Repetitive Outage Projects	MENTOR	Reduce Repeated Outages; Customer-outage-minutes avoided	19,084
51		**LVD Repetitive Outages Subtotal**	**4,500**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT KENT CITY-CASNOVIA LCP 287	90	1	Project	Repetitive Outage Projects	CASNOVIA	Reduce Repeated Outages; Customer-outage-minutes avoided	3,772
2	LVD Repetitive Outages	RPOUT KENT CITY-CASNOVIA LCP 787	90	1	Project	Repetitive Outage Projects	CASNOVIA	Reduce Repeated Outages; Customer-outage-minutes avoided	23,678
3	LVD Repetitive Outages	RPOUT CASCADE-PEACE STREET LCP 403	90	1	Project	Repetitive Outage Projects	LOWELL	Reduce Repeated Outages; Customer-outage-minutes avoided	13,839
4	LVD Repetitive Outages	RPOUT LOOMIS-LOOMIS ROAD LCP 604	90	1	Project	Repetitive Outage Projects	OLIVE	Reduce Repeated Outages; Customer-outage-minutes avoided	66,902
5	LVD Repetitive Outages	RPOUT EAST TAWAS-LINCOLN STREET LCP 48	90	1	Project	Repetitive Outage Projects	TAWAS CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	62,931
6	LVD Repetitive Outages	RPOUT BALZER-SANDERS LCP CKT	90	1	Project	Repetitive Outage Projects	LESLIE	Reduce Repeated Outages; Customer-outage-minutes avoided	95,154
7	LVD Repetitive Outages	RPOUT MILL GROVE-ALLEGAN HYDRO LCP 809	90	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	19,824
8	LVD Repetitive Outages	RPOUT ALGER-SKIDWAY LCP 951	90	1	Project	Repetitive Outage Projects	RICHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	11,481
9	LVD Repetitive Outages	RPOUT IRISH ROAD-CRYSTALWOOD LCP 709	90	1	Project	Repetitive Outage Projects	DAVISON	Reduce Repeated Outages; Customer-outage-minutes avoided	15,726
10	LVD Repetitive Outages	RPOUT SPICEBUSH-LESTER LAKE LCP 903	90	1	Project	Repetitive Outage Projects	GENEVA	Reduce Repeated Outages; Customer-outage-minutes avoided	35,458
11	LVD Repetitive Outages	RPOUT DUNBAR-HULL LCP 734	90	1	Project	Repetitive Outage Projects	MONROE	Reduce Repeated Outages; Customer-outage-minutes avoided	8,315
12	LVD Repetitive Outages	RPOUT FOREST GROVE-OTTOGAN LCP 583	90	1	Project	Repetitive Outage Projects	JAMESTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	5,013
13	LVD Repetitive Outages	RPOUT STANWOOD-TYLER ROAD LCP 212	90	1	Project	Repetitive Outage Projects	STANWOOD	Reduce Repeated Outages; Customer-outage-minutes avoided	10,059
14	LVD Repetitive Outages	RPOUT STANWOOD-TYLER ROAD LCP 864	90	1	Project	Repetitive Outage Projects	STANWOOD	Reduce Repeated Outages; Customer-outage-minutes avoided	32,920
15	LVD Repetitive Outages	RPOUT RATIGAN-MURRAY LAKE LCP 103	90	1	Project	Repetitive Outage Projects	OTISCO	Reduce Repeated Outages; Customer-outage-minutes avoided	28,237
16	LVD Repetitive Outages	RPOUT MOSEL-ALLEN LCP 383	90	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	66,756
17	LVD Repetitive Outages	RPOUT THORNTON-WEST RIVER RD LCP 219	90	1	Project	Repetitive Outage Projects	SANFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	90,703
18	LVD Repetitive Outages	RPOUT THORNTON-WEST RIVER RD LCP 427	90	1	Project	Repetitive Outage Projects	SANFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	8,866
19	LVD Repetitive Outages	RPOUT THORNTON-WEST RIVER RD LCP 856	90	1	Project	Repetitive Outage Projects	SANFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	3,580
20	LVD Repetitive Outages	RPOUT MURNER-VAN TYLE LCP 930	90	1	Project	Repetitive Outage Projects	GAYLORD	Reduce Repeated Outages; Customer-outage-minutes avoided	4,925
21	LVD Repetitive Outages	RPOUT STURGEON-ST ANDREWS LCP 77	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	11,919
22	LVD Repetitive Outages	RPOUT SPRING ARBOR-ARBOR HILLS LCP 756	90	1	Project	Repetitive Outage Projects	SPRING ARBOR	Reduce Repeated Outages; Customer-outage-minutes avoided	21,754
23	LVD Repetitive Outages	RPOUT STARKS-LEE LCP 872	90	1	Project	Repetitive Outage Projects	JEROME	Reduce Repeated Outages; Customer-outage-minutes avoided	29,343
24	LVD Repetitive Outages	RPOUT BEAVER-CRUMP LCP 3	90	1	Project	Repetitive Outage Projects	KAWKAWLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	24,380
25	LVD Repetitive Outages	RPOUT BRICKER-STOREY ROAD LCP 62	90	1	Project	Repetitive Outage Projects	BELDING	Reduce Repeated Outages; Customer-outage-minutes avoided	128,985
26	LVD Repetitive Outages	RPOUT CENTREVILLE-LAKE TEMPLENE LCP 843	90	1	Project	Repetitive Outage Projects	CENTREVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	94,382
27	LVD Repetitive Outages	RPOUT GREENWOOD-RAU ROAD LCP 867	90	1	Project	Repetitive Outage Projects	MOFFATT	Reduce Repeated Outages; Customer-outage-minutes avoided	11,566
28	LVD Repetitive Outages	RPOUT BEAVERTON-TOBACCO LCP 348	90	1	Project	Repetitive Outage Projects	BEAVERTON	Reduce Repeated Outages; Customer-outage-minutes avoided	74,392
29	LVD Repetitive Outages	RPOUT CARSON CITY-HOSPITAL LCP 488	90	1	Project	Repetitive Outage Projects	CARSON CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	24,423
30	LVD Repetitive Outages	RPOUT MERSON-DUCK LAKE LCP 854	90	1	Project	Repetitive Outage Projects	TROWBRIDGE	Reduce Repeated Outages; Customer-outage-minutes avoided	37,569
31	LVD Repetitive Outages	RPOUT LETTS ROAD-WALKER LCP 404	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	40,102
32	LVD Repetitive Outages	RPOUT LETTS ROAD-WALKER LCP 771	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	107,347
33	LVD Repetitive Outages	RPOUT MCCRACKEN-LEON LCP 365	90	1	Project	Repetitive Outage Projects	NORTON SHORES	Reduce Repeated Outages; Customer-outage-minutes avoided	5,287
34	LVD Repetitive Outages	RPOUT SUTTONS BAY-SUTTONS BAY LCP 511	90	1	Project	Repetitive Outage Projects	SUTTONS BAY	Reduce Repeated Outages; Customer-outage-minutes avoided	7,158
35	LVD Repetitive Outages	RPOUT FRONTIER-TAMARACK ROAD LCP 610	90	1	Project	Repetitive Outage Projects	JEFFERSON	Reduce Repeated Outages; Customer-outage-minutes avoided	36,498
36	LVD Repetitive Outages	RPOUT MARION-GASCOM LCP 63	90	1	Project	Repetitive Outage Projects	MARION	Reduce Repeated Outages; Customer-outage-minutes avoided	39,509
37	LVD Repetitive Outages	RPOUT GLEN LAKE-BURDICKVILLE LCP 769	90	1	Project	Repetitive Outage Projects	CLEVELAND	Reduce Repeated Outages; Customer-outage-minutes avoided	106,244
38	LVD Repetitive Outages	RPOUT DONTZ ROAD-KOTT ROAD LCP 576	90	1	Project	Repetitive Outage Projects	MANISTEE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,175
39	LVD Repetitive Outages	RPOUT WEBB ROAD-PLAINFIELD LCP 607	90	1	Project	Repetitive Outage Projects	PLAINFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	11,454
40	LVD Repetitive Outages	RPOUT KENT CITY-TYRONE LCP 628	90	1	Project	Repetitive Outage Projects	KENT CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	24,188
41	LVD Repetitive Outages	RPOUT MANTON-DOWNTOWN LCP 203	90	1	Project	Repetitive Outage Projects	MANTON	Reduce Repeated Outages; Customer-outage-minutes avoided	9,164
42	LVD Repetitive Outages	RPOUT BROGAN-SOUTH LCP 103	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	37,863
43	LVD Repetitive Outages	RPOUT BALZER-COMSTOCK LCP 507	90	1	Project	Repetitive Outage Projects	LESLIE	Reduce Repeated Outages; Customer-outage-minutes avoided	62,505
44	LVD Repetitive Outages	RPOUT BABCOCK-DIVISION LCP 276	90	1	Project	Repetitive Outage Projects	SHERWOOD	Reduce Repeated Outages; Customer-outage-minutes avoided	31,766
45	LVD Repetitive Outages	RPOUT EDMORE-CEDAR LAKE LCP 788	90	1	Project	Repetitive Outage Projects	EDMORE	Reduce Repeated Outages; Customer-outage-minutes avoided	153,587
46	LVD Repetitive Outages	RPOUT DEWITT-DEWITT LCP 497	90	1	Project	Repetitive Outage Projects	DEWITT	Reduce Repeated Outages; Customer-outage-minutes avoided	26,907
47	LVD Repetitive Outages	RPOUT PIERSON-WHITEFISH LCP 603	90	1	Project	Repetitive Outage Projects	PIERSON	Reduce Repeated Outages; Customer-outage-minutes avoided	42,299
48	LVD Repetitive Outages	RPOUT GALESBURG-CHARLESTON LCP 464	90	1	Project	Repetitive Outage Projects	GALESBURG	Reduce Repeated Outages; Customer-outage-minutes avoided	7,995
49	LVD Repetitive Outages	RPOUT RODNEY-HORSE HEAD LAKE LCP 241	90	1	Project	Repetitive Outage Projects	COLFAX	Reduce Repeated Outages; Customer-outage-minutes avoided	24,159
50	LVD Repetitive Outages	RPOUT SAUGATUCK-DOUGLAS LCP 78	90	1	Project	Repetitive Outage Projects	DOUGLAS	Reduce Repeated Outages; Customer-outage-minutes avoided	31,091
51		**LVD Repetitive Outages Subtotal**	**4,500**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT KINGSLEY-WALTON LCP 771	90	1	Project	Repetitive Outage Projects	KINGSLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	21,869
2	LVD Repetitive Outages	RPOUT VIRGINIA PARK-CASTLE LCP 21	90	1	Project	Repetitive Outage Projects	HOLLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	27,961
3	LVD Repetitive Outages	RPOUT LAKE CITY-STITTSVILLE LCP 841	90	1	Project	Repetitive Outage Projects	LAKE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	72,852
4	LVD Repetitive Outages	RPOUT MESICK-SHERMAN LCP 760	90	1	Project	Repetitive Outage Projects	MESICK	Reduce Repeated Outages; Customer-outage-minutes avoided	28,906
5	LVD Repetitive Outages	RPOUT BEHNKE-RIVER RD LCP 469	90	1	Project	Repetitive Outage Projects	COLDWATER	Reduce Repeated Outages; Customer-outage-minutes avoided	50,755
6	LVD Repetitive Outages	RPOUT FIFTEEN MILE ROAD-15 MILE ROAD LCP CKT	90	1	Project	Repetitive Outage Projects	MARSHALL	Reduce Repeated Outages; Customer-outage-minutes avoided	150,377
7	LVD Repetitive Outages	RPOUT FROST-LONG LAKE LCP 291	90	1	Project	Repetitive Outage Projects	SUMMERFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	17,287
8	LVD Repetitive Outages	RPOUT BROGAN-BROGAN LCP 766	90	1	Project	Repetitive Outage Projects	HASTINGS	Reduce Repeated Outages; Customer-outage-minutes avoided	45,678
9	LVD Repetitive Outages	RPOUT RATIGAN-MURRAY LAKE LCP 274	90	1	Project	Repetitive Outage Projects	OTISCO	Reduce Repeated Outages; Customer-outage-minutes avoided	15,731
10	LVD Repetitive Outages	RPOUT STANLEY-NORTHLAND LCP 417	90	1	Project	Repetitive Outage Projects	MT MORRIS	Reduce Repeated Outages; Customer-outage-minutes avoided	38,850
11	LVD Repetitive Outages	RPOUT WEALTHY STREET-WATSON LCP CKT	90	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	20,773
12	LVD Repetitive Outages	RPOUT ATLAS-GOODRICH LCP 152	90	1	Project	Repetitive Outage Projects	GOODRICH	Reduce Repeated Outages; Customer-outage-minutes avoided	29,687
13	LVD Repetitive Outages	RPOUT CAMELOT LAKE-LOOMIS LCP 202	90	1	Project	Repetitive Outage Projects	JASPER	Reduce Repeated Outages; Customer-outage-minutes avoided	85,450
14	LVD Repetitive Outages	RPOUT STANDISH-STANDISH LCP 783	90	1	Project	Repetitive Outage Projects	STANDISH	Reduce Repeated Outages; Customer-outage-minutes avoided	17,060
15	LVD Repetitive Outages	RPOUT CONVIS-CONVIS LCP 201	90	1	Project	Repetitive Outage Projects	PENNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	1,867
16	LVD Repetitive Outages	RPOUT CARSON CITY-BUTTERNUT LCP 706	90	1	Project	Repetitive Outage Projects	CARSON CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	35,188
17	LVD Repetitive Outages	RPOUT COOPER-COOPER CENTER LCP 224	90	1	Project	Repetitive Outage Projects	COOPER	Reduce Repeated Outages; Customer-outage-minutes avoided	26,034
18	LVD Repetitive Outages	RPOUT CHESTER-MORRELL LCP 221	90	1	Project	Repetitive Outage Projects	CARMEL	Reduce Repeated Outages; Customer-outage-minutes avoided	27,638
19	LVD Repetitive Outages	RPOUT JOPPA-BECKLEY LCP 887	90	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	13,071
20	LVD Repetitive Outages	RPOUT LINCOLN-LOST LAKE LCP 639	90	1	Project	Repetitive Outage Projects	LINCOLN	Reduce Repeated Outages; Customer-outage-minutes avoided	159,783
21	LVD Repetitive Outages	RPOUT HOWARD CITY-MORLEY LCP 5075	90	1	Project	Repetitive Outage Projects	MORLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	49,665
22	LVD Repetitive Outages	RPOUT BATTEESE-MUNITH LCP 896	90	1	Project	Repetitive Outage Projects	WATERLOO	Reduce Repeated Outages; Customer-outage-minutes avoided	154,198
23	LVD Repetitive Outages	RPOUT GODFREY-LOWELL LCP 341	90	1	Project	Repetitive Outage Projects	KEENE	Reduce Repeated Outages; Customer-outage-minutes avoided	37,878
24	LVD Repetitive Outages	RPOUT CLIMAX-CLIMAX LCP 728	90	1	Project	Repetitive Outage Projects	CLIMAX	Reduce Repeated Outages; Customer-outage-minutes avoided	9,215
25	LVD Repetitive Outages	RPOUT PITTSFORD-CHURCH ROAD LCP 583	90	1	Project	Repetitive Outage Projects	WHEATLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	211,418
26	LVD Repetitive Outages	RPOUT PITTSFORD-BIRD LAKE LCP 928	90	1	Project	Repetitive Outage Projects	HILLSDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	66,102
27	LVD Repetitive Outages	RPOUT RODNEY-RODNEY LCP 618	90	1	Project	Repetitive Outage Projects	COLFAX	Reduce Repeated Outages; Customer-outage-minutes avoided	4,994
28	LVD Repetitive Outages	RPOUT ARCADIA-PLEASANTON LCP 268	90	1	Project	Repetitive Outage Projects	JOYFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	23,331
29	LVD Repetitive Outages	RPOUT PALO-PALO LCP 175	90	1	Project	Repetitive Outage Projects	N PLAINS	Reduce Repeated Outages; Customer-outage-minutes avoided	32,861
30	LVD Repetitive Outages	RPOUT INDIAN RIVER-TOPINABEE LCP 5701	90	1	Project	Repetitive Outage Projects	TUSCARORA	Reduce Repeated Outages; Customer-outage-minutes avoided	27,483
31	LVD Repetitive Outages	RPOUT TWIN LAKE-TWIN LAKE LCP 356	90	1	Project	Repetitive Outage Projects	HOLTON	Reduce Repeated Outages; Customer-outage-minutes avoided	20,504
32	LVD Repetitive Outages	RPOUT SPRINGPORT-SPRINGPORT LCP 370	90	1	Project	Repetitive Outage Projects	SPRINGPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	12,640
33	LVD Repetitive Outages	RPOUT CASCO-HAWKHEAD LCP 452	90	1	Project	Repetitive Outage Projects	CASCO	Reduce Repeated Outages; Customer-outage-minutes avoided	5,790
34	LVD Repetitive Outages	RPOUT TRUFANT-HUNTER LAKE LCP 664	90	1	Project	Repetitive Outage Projects	DOUGLASS	Reduce Repeated Outages; Customer-outage-minutes avoided	20,460
35	LVD Repetitive Outages	RPOUT MAYFAIR-MAYFAIR LCP 386	90	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	11,615
36	LVD Repetitive Outages	RPOUT WURTSMITH-MISSION LCP 664	90	1	Project	Repetitive Outage Projects	AU SABLE	Reduce Repeated Outages; Customer-outage-minutes avoided	39,543
37	LVD Repetitive Outages	RPOUT GREENBUSH-GREENBUSH LCP 555	90	1	Project	Repetitive Outage Projects	GREENBUSH	Reduce Repeated Outages; Customer-outage-minutes avoided	99,243
38	LVD Repetitive Outages	RPOUT LOVEJOY-BRADEN LCP 915	90	1	Project	Repetitive Outage Projects	ARGENTINE	Reduce Repeated Outages; Customer-outage-minutes avoided	32,500
39	LVD Repetitive Outages	RPOUT COCHRAN-KALAMO LCP 763	90	1	Project	Repetitive Outage Projects	CHARLOTTE	Reduce Repeated Outages; Customer-outage-minutes avoided	21,554
40	LVD Repetitive Outages	RPOUT BLUE WATER-SCOTT ROAD LCP 394	90	1	Project	Repetitive Outage Projects	ST JOHNS	Reduce Repeated Outages; Customer-outage-minutes avoided	24,045
41	LVD Repetitive Outages	RPOUT PECK ROAD-WISE ROAD LCP 484	90	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	25,390
42	LVD Repetitive Outages	RPOUT ELLIS-DANGL LCP 286	90	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	103,587
43	LVD Repetitive Outages	RPOUT ABBE-HWY 33 LCP 207	90	1	Project	Repetitive Outage Projects	LOUD	Reduce Repeated Outages; Customer-outage-minutes avoided	6,122
44	LVD Repetitive Outages	RPOUT WILDER-WILDER LCP 129	90	1	Project	Repetitive Outage Projects	ECKFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	15,451
45	LVD Repetitive Outages	RPOUT SPRUCE ROAD-BLACK RIVER LCP 821	90	1	Project	Repetitive Outage Projects	CALEDONIA	Reduce Repeated Outages; Customer-outage-minutes avoided	50,710
46	LVD Repetitive Outages	RPOUT VANDERBILT-WOLVERINE LCP CKT	90	1	Project	Repetitive Outage Projects	VANDERBILT	Reduce Repeated Outages; Customer-outage-minutes avoided	128,650
47	LVD Repetitive Outages	RPOUT FOREMAN-VERGENNES LCP 884	90	1	Project	Repetitive Outage Projects	ADA	Reduce Repeated Outages; Customer-outage-minutes avoided	21,419
48	LVD Repetitive Outages	RPOUT SIMMONS-DAM ROAD LCP 696	90	1	Project	Repetitive Outage Projects	WEST BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	21,581
49	LVD Repetitive Outages	RPOUT PRICE ROAD-PRICE LCP 71	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	23,014
50	LVD Repetitive Outages	RPOUT SHARON HOLLOW-ENGLISH ROAD LCP 218	90	1	Project	Repetitive Outage Projects	MANCHESTER	Reduce Repeated Outages; Customer-outage-minutes avoided	86,190
51		**LVD Repetitive Outages Subtotal**	**4,500**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 16 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT SNYDER-CRITTENDEN LAKE LCP CKT	90	1	Project	Repetitive Outage Projects	DICKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	14,231
2	LVD Repetitive Outages	RPOUT ASH ROAD-STERLING ROAD LCP 170	90	1	Project	Repetitive Outage Projects	LITCHFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	67,647
3	LVD Repetitive Outages	RPOUT FIVE CHANNELS HYDRO-DISTRIBUTION LCP 10	90	1	Project	Repetitive Outage Projects	OSCODA	Reduce Repeated Outages; Customer-outage-minutes avoided	10,340
4	LVD Repetitive Outages	RPOUT BULLOCK-STEWART LCP 807	90	1	Project	Repetitive Outage Projects	LEE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,715
5	LVD Repetitive Outages	RPOUT HOMESTEAD-BEULAH LCP 5833	90	1	Project	Repetitive Outage Projects	BEULAH	Reduce Repeated Outages; Customer-outage-minutes avoided	21,127
6	LVD Repetitive Outages	RPOUT GREENSPIRE-CENTRE ST LCP 571	90	1	Project	Repetitive Outage Projects	PORTAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	29,646
7	LVD Repetitive Outages	RPOUT BURR OAK-INDUSTRIAL LCP 558	90	1	Project	Repetitive Outage Projects	BURR OAK	Reduce Repeated Outages; Customer-outage-minutes avoided	15,937
8	LVD Repetitive Outages	RPOUT STANDISH-STANDISH LCP 496	90	1	Project	Repetitive Outage Projects	STANDISH	Reduce Repeated Outages; Customer-outage-minutes avoided	57,614
9	LVD Repetitive Outages	RPOUT FINE LAKE-DOWLING LCP 560	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	29,942
10	LVD Repetitive Outages	RPOUT MENDON-M-60 LCP CKT	90	1	Project	Repetitive Outage Projects	MENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	23,617
11	LVD Repetitive Outages	RPOUT CASINO-LEATON LCP 276	90	1	Project	Repetitive Outage Projects	UNION	Reduce Repeated Outages; Customer-outage-minutes avoided	22,153
12	LVD Repetitive Outages	RPOUT LAKE MITCHELL-CANAL LCP 518	90	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoided	19,525
13	LVD Repetitive Outages	RPOUT MCBAIN-VOGEL CENTER LCP 64	90	1	Project	Repetitive Outage Projects	MCBAIN	Reduce Repeated Outages; Customer-outage-minutes avoided	198,234
14	LVD Repetitive Outages	RPOUT ONEKAMA-ONEKAMA LCP 1	90	1	Project	Repetitive Outage Projects	ONEKAMA	Reduce Repeated Outages; Customer-outage-minutes avoided	1,914
15	LVD Repetitive Outages	RPOUT OSHTEMO-HURD LCP 102	90	1	Project	Repetitive Outage Projects	OSHTEMO	Reduce Repeated Outages; Customer-outage-minutes avoided	30,506
16	LVD Repetitive Outages	RPOUT CONKLIN PARK-HOLLY LCP 922	90	1	Project	Repetitive Outage Projects	REYNOLDS	Reduce Repeated Outages; Customer-outage-minutes avoided	84,972
17	LVD Repetitive Outages	RPOUT HOMER-HOMER LCP 566	90	1	Project	Repetitive Outage Projects	HOMER	Reduce Repeated Outages; Customer-outage-minutes avoided	15,996
18	LVD Repetitive Outages	RPOUT LAMOREAUX-BALLPARK LCP 660	90	1	Project	Repetitive Outage Projects	PLAINFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	87,828
19	LVD Repetitive Outages	RPOUT RAVENNA-RAVENNA LCP 73	90	1	Project	Repetitive Outage Projects	RAVENNA	Reduce Repeated Outages; Customer-outage-minutes avoided	26,643
20	LVD Repetitive Outages	RPOUT WAMPLERS-FRANKLIN LCP 69	90	1	Project	Repetitive Outage Projects	MANCHESTER	Reduce Repeated Outages; Customer-outage-minutes avoided	56,249
21	LVD Repetitive Outages	RPOUT FAIRFIELD-JASPER LCP 660	90	1	Project	Repetitive Outage Projects	MADISON	Reduce Repeated Outages; Customer-outage-minutes avoided	26,175
22	LVD Repetitive Outages	RPOUT MORRELL-WEST AVENUE LCP 215	90	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	53,351
23	LVD Repetitive Outages	RPOUT GULL LAKE-WILLOW BEACH LCP 422	90	1	Project	Repetitive Outage Projects	PRAIRIEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	80,220
24	LVD Repetitive Outages	RPOUT SYLVAN-RURAL LCP 473	90	1	Project	Repetitive Outage Projects	CHELSEA	Reduce Repeated Outages; Customer-outage-minutes avoided	25,453
25	LVD Repetitive Outages	RPOUT SYLVAN-RURAL LCP 781	90	1	Project	Repetitive Outage Projects	CHELSEA	Reduce Repeated Outages; Customer-outage-minutes avoided	37,004
26	LVD Repetitive Outages	RPOUT GERRISH-LEGION LCP 526	90	1	Project	Repetitive Outage Projects	GRAYLING	Reduce Repeated Outages; Customer-outage-minutes avoided	36,682
27	LVD Repetitive Outages	RPOUT GERRISH-GOLF CLUB LCP 964	90	1	Project	Repetitive Outage Projects	ROSCOMMON	Reduce Repeated Outages; Customer-outage-minutes avoided	93,406
28	LVD Repetitive Outages	RPOUT FOUR MILE-WALKENT LCP CKT	90	1	Project	Repetitive Outage Projects	WALKER	Reduce Repeated Outages; Customer-outage-minutes avoided	64,595
29	LVD Repetitive Outages	RPOUT PENTWATER-CARROLL LCP 315	90	1	Project	Repetitive Outage Projects	PENTWATER	Reduce Repeated Outages; Customer-outage-minutes avoided	29,315
30	LVD Repetitive Outages	RPOUT RODNEY-RODNEY LCP 594	90	1	Project	Repetitive Outage Projects	COLFAX	Reduce Repeated Outages; Customer-outage-minutes avoided	16,103
31	LVD Repetitive Outages	RPOUT BRADFORD-DISTRIBUTION LCP 58	90	1	Project	Repetitive Outage Projects	LEE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,449
32	LVD Repetitive Outages	RPOUT ROSE CITY-KLACKING CREEK LCP 412	90	1	Project	Repetitive Outage Projects	ROSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	57,714
33	LVD Repetitive Outages	RPOUT BELLAIRE-DOWNTOWN LCP 966	90	1	Project	Repetitive Outage Projects	BELLAIRE	Reduce Repeated Outages; Customer-outage-minutes avoided	45,867
34	LVD Repetitive Outages	RPOUT ROTHBURY-NEW ERA LCP 619	90	1	Project	Repetitive Outage Projects	NEW ERA	Reduce Repeated Outages; Customer-outage-minutes avoided	27,036
35	LVD Repetitive Outages	RPOUT COLON-PALMER LCP 517	90	1	Project	Repetitive Outage Projects	COLON	Reduce Repeated Outages; Customer-outage-minutes avoided	5,734
36	LVD Repetitive Outages	RPOUT PENINSULA-MAPLETON LCP 124	90	1	Project	Repetitive Outage Projects	PENINSULA	Reduce Repeated Outages; Customer-outage-minutes avoided	7,771
37	LVD Repetitive Outages	RPOUT MORRICE-SOUTH MORRICE LCP CKT	90	1	Project	Repetitive Outage Projects	MORRICE	Reduce Repeated Outages; Customer-outage-minutes avoided	89,195
38	LVD Repetitive Outages	RPOUT FRANKFORT-ELBERTA LCP 328	90	1	Project	Repetitive Outage Projects	FRANKFORT	Reduce Repeated Outages; Customer-outage-minutes avoided	23,998
39	LVD Repetitive Outages	RPOUT JONESVILLE-MILNES LCP 429	90	1	Project	Repetitive Outage Projects	JONESVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	26,130
40	LVD Repetitive Outages	RPOUT EAST JORDAN-WILLIAMS STREET LCP 614	90	1	Project	Repetitive Outage Projects	EAST JORDAN	Reduce Repeated Outages; Customer-outage-minutes avoided	8,082
41	LVD Repetitive Outages	RPOUT DEAN ROAD-PARSHALLVILLE LCP 6	90	1	Project	Repetitive Outage Projects	HARTLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	34,008
42	LVD Repetitive Outages	RPOUT MARTIN-SHELBYVILLE LCP 74	90	1	Project	Repetitive Outage Projects	MARTIN	Reduce Repeated Outages; Customer-outage-minutes avoided	35,017
43	LVD Repetitive Outages	RPOUT DONTZ ROAD-KOTT ROAD LCP 716	90	1	Project	Repetitive Outage Projects	MANISTEE	Reduce Repeated Outages; Customer-outage-minutes avoided	22,742
44	LVD Repetitive Outages	RPOUT WEBB ROAD-HALE LCP 375	90	1	Project	Repetitive Outage Projects	PLAINFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	4,957
45	LVD Repetitive Outages	RPOUT BEDFORD-MEACHEM LCP 551	90	1	Project	Repetitive Outage Projects	JOHNSTOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	21,751
46	LVD Repetitive Outages	RPOUT FOX FARM-LINKE LCP 543	90	1	Project	Repetitive Outage Projects	FILER	Reduce Repeated Outages; Customer-outage-minutes avoided	27,251
47	LVD Repetitive Outages	RPOUT MIDDLEVILLE-BUSINESS LCP 666	90	1	Project	Repetitive Outage Projects	MIDDLEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	27,586
48	LVD Repetitive Outages	RPOUT BAGLEY-OTSEGO LAKE LCP 868	90	1	Project	Repetitive Outage Projects	GAYLORD	Reduce Repeated Outages; Customer-outage-minutes avoided	26,325
49	LVD Repetitive Outages	RPOUT BAGLEY-FREDERIC LCP 936	90	1	Project	Repetitive Outage Projects	GAYLORD	Reduce Repeated Outages; Customer-outage-minutes avoided	11,506
50	LVD Repetitive Outages	RPOUT CLUB-VILLAGE LCP 233	90	1	Project	Repetitive Outage Projects	LAKEWOOD CLUB	Reduce Repeated Outages; Customer-outage-minutes avoided	47,475
51	LVD Repetitive Outages	RPOUT RIX ROAD-UNDERPASS LCP 899	90	1	Project	Repetitive Outage Projects	OSHTEMO	Reduce Repeated Outages; Customer-outage-minutes avoided	11,327
52	LVD Repetitive Outages	RPOUT OVID-SHEPARDSVILLE LCP 511	90	1	Project	Repetitive Outage Projects	OVID	Reduce Repeated Outages; Customer-outage-minutes avoided	13,653
53	LVD Repetitive Outages	RPOUT NINETEEN MILE RD-CEMENT LCP 481	90	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	55,595
54	LVD Repetitive Outages	RPOUT LOCH ERIN-PENTECOST LCP 43	90	1	Project	Repetitive Outage Projects	FRANKLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	54,545
55	LVD Repetitive Outages	RPOUT GILKEY CREEK-WOLCOTT LCP 859	90	1	Project	Repetitive Outage Projects	BURTON	Reduce Repeated Outages; Customer-outage-minutes avoided	3,656
56	LVD Repetitive Outages	RPOUT ALDRICH-TRAVERSE LCP 242	90	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	76,058
57	LVD Repetitive Outages	RPOUT ALAMO-PINE GROVE LCP 430	90	1	Project	Repetitive Outage Projects	PINE GROVE	Reduce Repeated Outages; Customer-outage-minutes avoided	30,186
58	LVD Repetitive Outages	RPOUT ALAMO-PINE GROVE LCP 657	90	1	Project	Repetitive Outage Projects	PINE GROVE	Reduce Repeated Outages; Customer-outage-minutes avoided	24,172
59	LVD Repetitive Outages	RPOUT OBERLIN-PRATT LAKE LCP 709	90	1	Project	Repetitive Outage Projects	SAGE	Reduce Repeated Outages; Customer-outage-minutes avoided	10,992
60	LVD Repetitive Outages	RPOUT ABBE-ABBE LCP 280	90	1	Project	Repetitive Outage Projects	MENTOR	Reduce Repeated Outages; Customer-outage-minutes avoided	18,149
61	LVD Repetitive Outages	RPOUT HUNT ROAD-MOORE ROAD LCP 167	90	1	Project	Repetitive Outage Projects	ADRIAN	Reduce Repeated Outages; Customer-outage-minutes avoided	15,550
62	LVD Repetitive Outages	RPOUT GREGORY-UNADILLA LCP 794	90	1	Project	Repetitive Outage Projects	UNADILLA	Reduce Repeated Outages; Customer-outage-minutes avoided	208,608
63	LVD Repetitive Outages	RPOUT MANTON-DOWNTOWN LCP 28	90	1	Project	Repetitive Outage Projects	MANTON	Reduce Repeated Outages; Customer-outage-minutes avoided	27,014
64	LVD Repetitive Outages	RPOUT WIRTZ ROAD-BOWMANVILLE LCP 467	90	1	Project	Repetitive Outage Projects	BOURRET	Reduce Repeated Outages; Customer-outage-minutes avoided	29,092
65	LVD Repetitive Outages	RPOUT CRAWFORD-WINN LCP 611	90	1	Project	Repetitive Outage Projects	UNION	Reduce Repeated Outages; Customer-outage-minutes avoided	4,789
66	LVD Repetitive Outages	RPOUT WHITTEMORE-SAND LAKE LCP 117	90	1	Project	Repetitive Outage Projects	TAWAS	Reduce Repeated Outages; Customer-outage-minutes avoided	11,085
67	LVD Repetitive Outages	RPOUT BLUE STAR-PIER COVE LCP 619	90	1	Project	Repetitive Outage Projects	SAUGATUCK	Reduce Repeated Outages; Customer-outage-minutes avoided	20,982
68	LVD Repetitive Outages	RPOUT HARVARD LAKE-HARVARD LAKE LCP 226	90	1	Project	Repetitive Outage Projects	NELSON	Reduce Repeated Outages; Customer-outage-minutes avoided	26,443
69	LVD Repetitive Outages	RPOUT PRICE ROAD-MERIDIAN LCP 508	90	1	Project	Repetitive Outage Projects	SANFORD	Reduce Repeated Outages; Customer-outage-minutes avoided	60,131
70	LVD Repetitive Outages	RPOUT FLETCHER-BAY VIEW LCP 735	90	1	Project	Repetitive Outage Projects	BEAR CREEK	Reduce Repeated Outages; Customer-outage-minutes avoided	9,514
71	LVD Repetitive Outages	RPOUT BENSTON-DURHAM LCP 258	90	1	Project	Repetitive Outage Projects	LAKEWOOD CLUB	Reduce Repeated Outages; Customer-outage-minutes avoided	22,742
72	LVD Repetitive Outages	RPOUT MT PLEASANT-BROADWAY LCP 347	90	1	Project	Repetitive Outage Projects	MT PLEASANT	Reduce Repeated Outages; Customer-outage-minutes avoided	13,054
73	LVD Repetitive Outages	RPOUT GREENWOOD-RAU ROAD LCP 895	90	1	Project	Repetitive Outage Projects	MOFFATT	Reduce Repeated Outages; Customer-outage-minutes avoided	24,971
74	LVD Repetitive Outages	RPOUT BEAVERTON-TOBACCO LCP 511	90	1	Project	Repetitive Outage Projects	BEAVERTON	Reduce Repeated Outages; Customer-outage-minutes avoided	2,425
75	LVD Repetitive Outages	RPOUT FOOTE HYDRO-DISTRIBUTION LCP 49	90	1	Project	Repetitive Outage Projects	OSCODA	Reduce Repeated Outages; Customer-outage-minutes avoided	9,966
76	LVD Repetitive Outages	RPOUT LARKIN-LARKIN LCP 291	90	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	62,341
77	LVD Repetitive Outages	RPOUT GRAND BLANC-REID LCP 347	90	1	Project	Repetitive Outage Projects	GRAND BLANC	Reduce Repeated Outages; Customer-outage-minutes avoided	35,571
78	LVD Repetitive Outages	RPOUT OWOSSO-STEWART LCP 700	90	1	Project	Repetitive Outage Projects	OWOSSO	Reduce Repeated Outages; Customer-outage-minutes avoided	218,695
79	LVD Repetitive Outages	RPOUT MILTON-MILLPOND LCP 921	90	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	4,313
80	LVD Repetitive Outages	RPOUT AUGUSTA-AUGUSTA LCP 675	90	1	Project	Repetitive Outage Projects	AUGUSTA	Reduce Repeated Outages; Customer-outage-minutes avoided	3,198
81	LVD Repetitive Outages	RPOUT EVANSTON-EVANSTON LCP 420	90	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	40,524
82	LVD Repetitive Outages	RPOUT GRANDVILLE-CANAL LCP CKT	90	1	Project	Repetitive Outage Projects	GRANDVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	9,663
83	LVD Repetitive Outages	RPOUT MORENCI-MOREY LCP 373	90	1	Project	Repetitive Outage Projects	MORENCI	Reduce Repeated Outages; Customer-outage-minutes avoided	17,251
84	LVD Repetitive Outages	RPOUT CONVIS-WALNUT POINT LCP 461	90	1	Project	Repetitive Outage Projects	MARSHALL	Reduce Repeated Outages; Customer-outage-minutes avoided	16,675
85	LVD Repetitive Outages	RPOUT CONVIS-MAR CREEK LCP 555	90	1	Project	Repetitive Outage Projects	PENNFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	170,666
86	LVD Repetitive Outages	RPOUT DURAND-GAINES LCP 688	90	1	Project	Repetitive Outage Projects	DURAND	Reduce Repeated Outages; Customer-outage-minutes avoided	6,912
87	LVD Repetitive Outages	RPOUT ALLENDALE-BLENDON LCP 542	104	1	Project	Repetitive Outage Projects	POLKTON	Reduce Repeated Outages; Customer-outage-minutes avoided	7,645
88		**LVD Repetitive Outages Subtotal**	**7,844**						
89		**LVD Repetitive Outages Total**	**30,344**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	ALTEN AVE NE ECNC RSO	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
2	LVD Lines Rehabilitation	UNION AVE SE ESIC OHS	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
3	LVD Lines Rehabilitation	UNION AVE SE ESIC OHS	3	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
4	LVD Lines Rehabilitation	UNION AVE SE ESIC OHS	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
5	LVD Lines Rehabilitation	UNION AVE SE, WYOMING - RECONDUCTOR	135	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
6	LVD Lines Rehabilitation	W CHERRY ST CEDAR SPRINGS OHS N st	2	1	Project	Imminent Rehabilitation	CEDAR SPRINGS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
7	LVD Lines Rehabilitation	MORNINGSIDE DR SE, GR - PULL POLE	5	1	Project	Imminent Rehabilitation	E GD RAPIDS	Correct Conductor Clearance Violation ; Customers	24
8	LVD Lines Rehabilitation	Old th St SE Mister Car Wash UGS	5	1	Project	Imminent Rehabilitation	ADA	Improve Secondary Voltage ; Customers	5
9	LVD Lines Rehabilitation	M MAPLE CITY deteriorating	7	1	Project	Imminent Rehabilitation	CLEVELAND	Replace Deteriorated Pole ; Customers	242
10	LVD Lines Rehabilitation	S Lakeview Rd TRAV CITY	6	1	Project	Imminent Rehabilitation	TRAVERSE CITY	Relocate Electric With Structure Encroachment ; Customers	1
11	LVD Lines Rehabilitation	CMPLT - BAY ST, SGN; ODCE	39	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
12	LVD Lines Rehabilitation	DEMO - PARTRIDGE ST, FLINT - PULL PO	16	1	Project	Imminent Rehabilitation	FLINT	Improve Secondary Voltage ; Customers	5
13	LVD Lines Rehabilitation	DEMO - DUFFIELD RD FLUSHING	4	1	Project	Imminent Rehabilitation	FLUSHING	Correct Conductor Clearance Violation ; Customers	24
14	LVD Lines Rehabilitation	FA - FOREST AVE, BOYNE CITY - OHC	15	1	Project	Imminent Rehabilitation	EVANGELINE	Correct Conductor Clearance Violation ; Customers	24
15	LVD Lines Rehabilitation	FA - DALLAS AVE SE, GR - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
16	LVD Lines Rehabilitation	FA - MILE RD NE LOWELL PULL POLE	2	1	Project	Imminent Rehabilitation	GRATTAN	Correct Conductor Clearance Violation ; Customers	24
17	LVD Lines Rehabilitation	FA - E RD ST, GAYLORD - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
18	LVD Lines Rehabilitation	FA - STATE ST, SGN; ODCE	13	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
19	LVD Lines Rehabilitation	FA - BEMIS ST SE, GR - OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
20	LVD Lines Rehabilitation	FA - TOPHITH RD, GRASS LAKE - OHC	5	1	Project	Imminent Rehabilitation	STOCKBRIDGE	Correct Conductor Clearance Violation ; Customers	24
21	LVD Lines Rehabilitation	FA - PARK RD JACKSON - ODCE	20	1	Project	Imminent Rehabilitation	JACKSON	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
22	LVD Lines Rehabilitation	FA - WOODLAND DR, SPRUCE - POL	27	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole ; Customers	242
23	LVD Lines Rehabilitation	FA - THOMPSON, LOWELL - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
24	LVD Lines Rehabilitation	FA - MILE MORLEY-POWER BANK RP	11	1	Project	Imminent Rehabilitation	MORLEY	Correct Conductor Clearance Violation ; Customers	24
25	LVD Lines Rehabilitation	FA - TH AVE, ZEELAND - FRRE	11	1	Project	Imminent Rehabilitation	ZEELAND	Retire and Remove Unused Assets; Customers	58
26	LVD Lines Rehabilitation	FA - LAUREL AVE SE, GR - SVLT	39	1	Project	Imminent Rehabilitation	E GD RAPIDS	Improve Secondary Voltage ; Customers	5
27	LVD Lines Rehabilitation	FA - Alexander RD SE, GR - POL	8	1	Project	Imminent Rehabilitation	E GD RAPIDS	Replace Deteriorated Pole ; Customers	242
28	LVD Lines Rehabilitation	FA - STATE PARK DR, BYC; FRRE	13	1	Project	Imminent Rehabilitation	BAY CITY	Retire and Remove Unused Assets; Customers	58
29	LVD Lines Rehabilitation	FA - DAVIS AVE NW GR - DSRV	13	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Service Replacement ; Customers	1
30	LVD Lines Rehabilitation	FA - Gerald Miller ESIO OHL	16	1	Project	Imminent Rehabilitation	LOGAN	Improve Secondary Voltage ; Customers	5
31	LVD Lines Rehabilitation	FA - Gerald Miller SVLT	16	1	Project	Imminent Rehabilitation	LOGAN	Improve Secondary Voltage ; Customers	5
32	LVD Lines Rehabilitation	FA - WILSON AVE NW GR - STRL	18	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Repair Damaged Streetlight ; Customers	-
33	LVD Lines Rehabilitation	FA - OUTER DR W,TC - OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
34	LVD Lines Rehabilitation	FA - HICKORY ST, SPRING LK - POL	27	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole ; Customers	242
35	LVD Lines Rehabilitation	FA - PASSOLT ST, SAG; SVLT	29	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
36	LVD Lines Rehabilitation	FA - HASTINGS ST, BIRCH RUN - SVLT	37	1	Project	Imminent Rehabilitation	ALBEE	Improve Secondary Voltage ; Customers	5
37	LVD Lines Rehabilitation	FA - COOLIDGE AVE, SAG; SVLT	78	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
38	LVD Lines Rehabilitation	FA - RED PINE DR, STANWOOD - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
39	LVD Lines Rehabilitation	FA - E MAIN ST BURLINGTON - FRRE	2	1	Project	Imminent Rehabilitation	BURLINGTON	Retire and Remove Unused Assets; Customers	58
40	LVD Lines Rehabilitation	FA - E COURT ST, FLINT - POL - PP	27	1	Project	Imminent Rehabilitation	FLINT	Replace Deteriorated Pole ; Customers	242
41	LVD Lines Rehabilitation	FA - TITTABAWASSEE ST, ALGER - POL	9	1	Project	Imminent Rehabilitation	BOURRET	Replace Deteriorated Pole ; Customers	242
42	LVD Lines Rehabilitation	FA - MAINTENANCE RD, B FALLS - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
43	LVD Lines Rehabilitation	FA - N SAGINAW, FLINT - DSRV	17	1	Project	Imminent Rehabilitation	CHARLEVOIX	Deteriorated Service Replacement ; Customers	1
44	LVD Lines Rehabilitation	FA - RIDGE RD, EAST TAWAS; OHC	29	1	Project	Imminent Rehabilitation	TAWAS CITY	Correct Conductor Clearance Violation ; Customers	24
45	LVD Lines Rehabilitation	FA - VROOMAN RD, JACKSON - OHS	2	1	Project	Imminent Rehabilitation	SUMMIT	Deteriorated Service Replacement ; Customers	1
46	LVD Lines Rehabilitation	FA - TH AVE - FRRE	29	1	Project	Imminent Rehabilitation	ALLEGAN	Retire and Remove Unused Assets; Customers	58
47	LVD Lines Rehabilitation	FA - PRICE RD, RAVENNA - FRRE	5	1	Project	Imminent Rehabilitation	RAVENNA	Retire and Remove Unused Assets; Customers	58
48	LVD Lines Rehabilitation	FA - E ROOSEVELT, ASHLEY - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
49	LVD Lines Rehabilitation	FA - TH ST, FENNVILLE - FRRE	13	1	Project	Imminent Rehabilitation	FENNVILLE	Retire and Remove Unused Assets; Customers	58
50	LVD Lines Rehabilitation	FA - S MORENCI AVE MIO OHC	13	1	Project	Imminent Rehabilitation	MENTOR	Correct Conductor Clearance Violation ; Customers	24
51	LVD Lines Rehabilitation	FA - CLARK ST, WAYLAND - FRRE	5	1	Project	Imminent Rehabilitation	WAYLAND	Retire and Remove Unused Assets; Customers	58
52	LVD Lines Rehabilitation	FA - TRAUM DR, SAG; SVLT	63	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
53	LVD Lines Rehabilitation	FA - TYGH RD, HORTON - OHC	15	1	Project	Imminent Rehabilitation	HANOVER	Correct Conductor Clearance Violation ; Customers	24
54	LVD Lines Rehabilitation	FA - WAYBURN AVE SW - POL	5	1	Project	Imminent Rehabilitation	GRANDVILLE	Replace Deteriorated Pole ; Customers	242
55	LVD Lines Rehabilitation	FA - WEISS ST, SAG; SVLT	21	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
56	LVD Lines Rehabilitation	FA - PEALE DR, SAG; SVLT	11	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
57	LVD Lines Rehabilitation	FA - TOWERLINE RD, HALE - SVLT	6	1	Project	Imminent Rehabilitation	PLAINFIELD	Improve Secondary Voltage ; Customers	5
58	LVD Lines Rehabilitation	FA - S CHURCH, LINCOLN - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
59	LVD Lines Rehabilitation	FA - BUCHANAN AVE SW WYOMING - POL	7	1	Project	Imminent Rehabilitation	KENTWOOD	Replace Deteriorated Pole ; Customers	242
60	LVD Lines Rehabilitation	FA - W LAKESIDE, WEST BRANCH - SVLT	6	1	Project	Imminent Rehabilitation	MOFFATT	Improve Secondary Voltage ; Customers	5
61		**LVD Lines Rehabilitation Subtotal (Imminent Rehabilitation)**	**1,067**						

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($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA - EDWIN ST, BOYNE CITY - OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
2	LVD Lines Rehabilitation	FA - AVEONLEA ST SW We Care ow sec	14	1	Project	Imminent Rehabilitation	WYOMING	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
3	LVD Lines Rehabilitation	FA - N STATE RD ALMA; ODCE	7	1	Project	Imminent Rehabilitation	ALMA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
4	LVD Lines Rehabilitation	FA - N STATE RD ALMA; ODCE UGS	2	1	Project	Imminent Rehabilitation	ALMA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
5	LVD Lines Rehabilitation	FA - W WESTOVER,E TAWAS - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
6	LVD Lines Rehabilitation	FA - ALPINE RD, GAYLORD - OHC	15	1	Project	Imminent Rehabilitation	GAYLORD	Correct Conductor Clearance Violation ; Customers	24
7	LVD Lines Rehabilitation	FA - CONCORD RD, JONESVILLE - OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
8	LVD Lines Rehabilitation	FA - BYRON CENTER AVE SW, BC - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
9	LVD Lines Rehabilitation	FA - TH ST, PLAINWELL - SVLT	13	1	Project	Imminent Rehabilitation	MARTIN	Improve Secondary Voltage ; Customers	5
10	LVD Lines Rehabilitation	FA - CRESCENT DR, MECOSTA - SVLT	0	1	Project	Imminent Rehabilitation	MECOSTA	Improve Secondary Voltage ; Customers	5
11	LVD Lines Rehabilitation	FA - E VAN BUREN RD, WHEELER - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
12	LVD Lines Rehabilitation	FA - BURROWS/BURROWS ANDREW, SAG; SVLT	72	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
13	LVD Lines Rehabilitation	FA - BURROWS/BURROWS BURHAM, SAG; SVLT	13	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
14	LVD Lines Rehabilitation	FA - DELAWARE BLVD SAG ; SVLT	25	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
15	LVD Lines Rehabilitation	FA - HWY NB BEFORE EXIT - OHC	15	1	Project	Imminent Rehabilitation	GERRISH	Correct Conductor Clearance Violation ; Customers	24
16	LVD Lines Rehabilitation	FA - WEALTHY ST/INDIANA PT. - SVLT	260	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
17	LVD Lines Rehabilitation	FA - WEALTHY ST/INDIANA PT. - SVLT	71	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
18	LVD Lines Rehabilitation	FA - WEALTHY ST/INDIANA PULL POLE - SVLT	34	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
19	LVD Lines Rehabilitation	FA - WEALTHY ST/INDIANA RSO - SVLT	2	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Improve Secondary Voltage ; Customers	5
20	LVD Lines Rehabilitation	FA E OAK ST FRE SVLT	40	1	Project	Imminent Rehabilitation	FREMONT	Improve Secondary Voltage ; Customers	5
21	LVD Lines Rehabilitation	FA CEDAR RIVER RD MANCELONA	26	1	Project	Imminent Rehabilitation	KEARNEY	Deteriorated Service Replacement ; Customers	1
22	LVD Lines Rehabilitation	FA Hutchinson St Big Rapids UGL	60	1	Project	Imminent Rehabilitation	BIG RAPIDS	Retire and Remove Unused Assets; Customers	58
23	LVD Lines Rehabilitation	FA COURT ST, SAG; SVLT ECNC UPO	3	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
24	LVD Lines Rehabilitation	FA COURT ST, SAG; SVLT ESIC OHL	21	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
25	LVD Lines Rehabilitation	FA MAC DR BELDING	9	1	Project	Imminent Rehabilitation	BELDING	Improve Secondary Voltage ; Customers	5
26	LVD Lines Rehabilitation	FA - RAINBOW PARK TRL, MIO - OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
27	LVD Lines Rehabilitation	FA CEDAR ST MANCELONA	17	1	Project	Imminent Rehabilitation	MANCELONA	Deteriorated Service Replacement ; Customers	1
28	LVD Lines Rehabilitation	FA HANCOCK ST, SAG; SVLT	13	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
29	LVD Lines Rehabilitation	FA ELDER DR CONKLIN SVLT	6	1	Project	Imminent Rehabilitation	COOPERSVILLE	Improve Secondary Voltage ; Customers	5
30	LVD Lines Rehabilitation	FA- S SUMAC AVE, WHITE CLOUD -SVLT	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
31	LVD Lines Rehabilitation	FA S WISE RD MT PLEASANT-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
32	LVD Lines Rehabilitation	FA- Van Appel Dr FLRE	28	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole ; Customers	242
33	LVD Lines Rehabilitation	FA- E GENESEE AVE, SAGINAW-PVLT	32	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Primary Voltage ; Customers	520
34	LVD Lines Rehabilitation	FA- Duck Lake Rd - DSRV	7	1	Project	Imminent Rehabilitation	FRUITLAND	Deteriorated Service Replacement ; Customers	1
35	LVD Lines Rehabilitation	FA Block of Stadium Dr, Kalamazoo	19	1	Project	Imminent Rehabilitation	KALAMAZOO	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
36	LVD Lines Rehabilitation	FA BURLINGAME AVE SW	7	1	Project	Imminent Rehabilitation	WYOMING	Improve Secondary Voltage ; Customers	5
37	LVD Lines Rehabilitation	FA S CIRCLE DR NE, KALKASKA - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
38	LVD Lines Rehabilitation	FA BUCHANAN AVE SW WYOMING	2	1	Project	Imminent Rehabilitation	WYOMING	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
39	LVD Lines Rehabilitation	FA- N EDGAR RD, SIX LAKES - POL	27	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole ; Customers	242
40	LVD Lines Rehabilitation	FA W OTSEGO LK, GAYLORD	15	1	Project	Imminent Rehabilitation	GAYLORD	Correct Conductor Clearance Violation ; Customers	24
41	LVD Lines Rehabilitation	FA FOREST RD OSDA SVLT	12	1	Project	Imminent Rehabilitation	BALDWIN	Improve Secondary Voltage ; Customers	5
42	LVD Lines Rehabilitation	FA W RILEY THOMPSON RD DSRV	37	1	Project	Imminent Rehabilitation	WHITEHALL	Deteriorated Service Replacement ; Customers	1
43	LVD Lines Rehabilitation	FA Leonard ST NW, Grand Rapids A	8	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
44	LVD Lines Rehabilitation	FA ND, HUDSONVILLE - GUYING	6	1	Project	Imminent Rehabilitation	HUDSONVILLE	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
45	LVD Lines Rehabilitation	FA FIRST ST KALKASKA	15	1	Project	Imminent Rehabilitation	KALKASKA	Improve Secondary Voltage ; Customers	5
46	LVD Lines Rehabilitation	FA MIDFIELD _ SVLT	42	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
47	LVD Lines Rehabilitation	FA HARVEY ST MUS PMBC	12	1	Project	Imminent Rehabilitation	NORTON SHORES	Correct Padmount to Building Clearance Violation ; Customers	1
48	LVD Lines Rehabilitation	FA Burt Lake View Drive	46	1	Project	Imminent Rehabilitation	PELLSTON	Relocate Electric With Structure Encroachment ; Customers	1
49	LVD Lines Rehabilitation	FA S LAKE ST LELAND_OHL	12	1	Project	Imminent Rehabilitation	LELAND	Improve Secondary Voltage ; Customers	5
50	LVD Lines Rehabilitation	FA MAIN ST EAST JORDAN	17	1	Project	Imminent Rehabilitation	EAST JORDAN	Deteriorated Service Replacement ; Customers	1
51	LVD Lines Rehabilitation	FA SATTERLY LAKE RD, MANCELONA SVLT	15	1	Project	Imminent Rehabilitation	MANCELONA	Improve Secondary Voltage ; Customers	5
52	LVD Lines Rehabilitation	FA RILEY ST HUDSONVILLE -POL	6	1	Project	Imminent Rehabilitation	JAMESTOWN	Replace Deteriorated Pole ; Customers	242
53	LVD Lines Rehabilitation	FA Byron Center Ave - Sec Pole	5	1	Project	Imminent Rehabilitation	BYRON	Replace Deteriorated Pole ; Customers	242
54	LVD Lines Rehabilitation	FA WISCASSET LN ALDEN	11	1	Project	Imminent Rehabilitation	FOREST HOME	Replace Deteriorated Pole ; Customers	242
55	LVD Lines Rehabilitation	FA N BRADLEY HWY ROG CITY	19	1	Project	Imminent Rehabilitation	ROGERS CITY	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
56	LVD Lines Rehabilitation	FA CHIPPEWA ST JENISON-deterioronly	5	1	Project	Imminent Rehabilitation	GEORGETOWN	Replace Deteriorated Pole ; Customers	242
57	LVD Lines Rehabilitation	FA Cascade Thorncrest leaning pole	40	1	Project	Imminent Rehabilitation	LOWELL	Replace Deteriorated Pole ; Customers	242
58	LVD Lines Rehabilitation	FA MAPLE CITY/SUGARLOAF LCP J	273	1	Project	Imminent Rehabilitation	CLEVELAND	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
59	LVD Lines Rehabilitation	FA NIAGARA/ADAMS STORCH ST Y, SAG; SVLT	50	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
60	LVD Lines Rehabilitation	FA NIAGARA/ADAMS STORCH ST Z, SAG; SVLT	35	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
61		**LVD Lines Rehabilitation Subtotal (Imminent Rehabilitation)**	**1,681**						

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA REHAB WILMOTT_WILMOTT,	650	1	Project	Imminent Rehabilitation	OTSEGO	Replace Deteriorated Underground Primary ; Customers	43
2	LVD Lines Rehabilitation	FA_SVLT_ ABBOTT RD_ROSE CITY	9	1	Project	Imminent Rehabilitation	ROSE CITY	Improve Secondary Voltage ; Customers	5
3	LVD Lines Rehabilitation	FA_SVLT_ ISLAND LAKE RD_ROSE CITY	13	1	Project	Imminent Rehabilitation	ROSE CITY	Improve Secondary Voltage ; Customers	5
4	LVD Lines Rehabilitation	FA- NORTHLAND,#,BR-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
5	LVD Lines Rehabilitation	FA- DOUGLAS LAKE,PELLSTON-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
6	LVD Lines Rehabilitation	FA- E RIVER RD-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
7	LVD Lines Rehabilitation	FA- MINER RD PARMA-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
8	LVD Lines Rehabilitation	FA- N SCHEURMANN RD-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
9	LVD Lines Rehabilitation	FA- GARFIELD,BIG RAPIDS-PVLT	32	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Primary Voltage ; Customers	520
10	LVD Lines Rehabilitation	FA- HEIGHTSVIEW,HOUGHTON LAKE-RFIR	2	1	Project	Imminent Rehabilitation	BUTTERFIELD	Correct Radio Frequency Interference ; Customers	1
11	LVD Lines Rehabilitation	FA- WALLACE NE,MANCELONA-RELOC GUY	19	1	Project	Imminent Rehabilitation	CHARLEVOIX	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
12	LVD Lines Rehabilitation	FA- EASTBOOK SE,GR-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
13	LVD Lines Rehabilitation	FA- S THOMAS RD, SAGINAW-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
14	LVD Lines Rehabilitation	FA- RENO RD, WHITTEMORE-SVLT	16	1	Project	Imminent Rehabilitation	PRESCOTT	Improve Secondary Voltage ; Customers	5
15	LVD Lines Rehabilitation	FA- M , STERLING-SVLT	16	1	Project	Imminent Rehabilitation	STANDISH	Improve Secondary Voltage ; Customers	5
16	LVD Lines Rehabilitation	FA- S MARBLE RD, LOWELL-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
17	LVD Lines Rehabilitation	FA- MILE RD NW, GRAND RAPIDS-POL	27	1	Project	Imminent Rehabilitation	CHARLEVOIX	Replace Deteriorated Pole ; Customers	242
18	LVD Lines Rehabilitation	FA- W DAVID HWY,SARANAC-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
19	LVD Lines Rehabilitation	FA- ABRAHAM DR NE, LOWELL-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
20	LVD Lines Rehabilitation	FA- W BROOMFIELD RD-PVLT	32	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Primary Voltage ; Customers	520
21	LVD Lines Rehabilitation	FA- N TH ST #B, Kzoo-OHC	15	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Conductor Clearance Violation ; Customers	24
22	LVD Lines Rehabilitation	FA- N HURON RD-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
23	LVD Lines Rehabilitation	FA- W COLDWATER, FLUSHING-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
24	LVD Lines Rehabilitation	FA- TH AVE, SoHa -PMBC	25	1	Project	Imminent Rehabilitation	CHARLEVOIX	Correct Padmount to Building Clearance Violation ; Customers	1
25	LVD Lines Rehabilitation	FA- W CO LINE, HOWARD CITY-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
26	LVD Lines Rehabilitation	FA- BROOMFIELD RD, MT PLEASANT-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
27	LVD Lines Rehabilitation	FA- FOREST ST, IONIA-SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
28	LVD Lines Rehabilitation	FAIL - N INDIAN LAKE DR, SCOTTS	13	1	Project	Imminent Rehabilitation	PORTAGE	Improve Secondary Voltage ; Customers	5
29	LVD Lines Rehabilitation	FAILURE STREETLIGHT -MUSKEGON CAUSEWAY	18	1	Project	Imminent Rehabilitation	MUSKEGON	Repair Damaged Streetlight ; Customers	0
30	LVD Lines Rehabilitation	FA-Villiage of Lincoln lights - SVLT	16	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
31	LVD Lines Rehabilitation	HPBM bayberry point dr nw,FA,DELROY	8	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Repair Holes in Padmount Base ; Customers	1
32	LVD Lines Rehabilitation	HPMT OLD KENT RD SE, GRAND RAPIDS	6	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Repair Hole in Padmount Enclosure ; Customers	1
33	LVD Lines Rehabilitation	INSP TH AVE POLE RELOCATE OHL	137	1	Project	Imminent Rehabilitation	CASCO	Replace Deteriorated Pole ; Customers	242
34	LVD Lines Rehabilitation	INSP TH AVE POLE RELOCATE UGL	50	1	Project	Imminent Rehabilitation	CASCO	Replace Deteriorated Pole ; Customers	242
35	LVD Lines Rehabilitation	OHC E LAKE MITCHELL DR - ORIGINAL	6	1	Project	Imminent Rehabilitation	CADILLAC	Correct Conductor Clearance Violation ; Customers	24
36	LVD Lines Rehabilitation	OHS- BURROWS/BURROWS ANDREW Andrew	2	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
37	LVD Lines Rehabilitation	POL NEW HOLLAND HUDV	2	1	Project	Imminent Rehabilitation	HUDSONVILLE	Replace Deteriorated Pole ; Customers	242
38	LVD Lines Rehabilitation	POL ND AVE HUDV	3	1	Project	Imminent Rehabilitation	HUDSONVILLE	Replace Deteriorated Pole ; Customers	242
39	LVD Lines Rehabilitation	POL BALSAM DR & HOPE CT HUDV	2	1	Project	Imminent Rehabilitation	HUDSONVILLE	Replace Deteriorated Pole ; Customers	242
40	LVD Lines Rehabilitation	POL CHICAGO DR SCHOOL HUDV	3	1	Project	Imminent Rehabilitation	HUDSONVILLE	Replace Deteriorated Pole ; Customers	242
41	LVD Lines Rehabilitation	Warren Ave Alley Secondary Replc - FA	41	1	Project	Imminent Rehabilitation	BIG RAPIDS	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	12
42	LVD Lines Rehabilitation	FA DEWEY SEATING LCP CKT	982	1	Project	Imminent Rehabilitation	GRAND RAPIDS	Replace Deteriorated Pole ; Customers	3809
43	LVD Lines Rehabilitation	FA PENTWATER_CARROLL LCP ESIC	850	1	Project	Imminent Rehabilitation	PENTWATER	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	105
44	LVD Lines Rehabilitation	FA PENTWATER_CARROLL LCP ESIC	1,330	1	Project	Imminent Rehabilitation	PENTWATER	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	55
45	LVD Lines Rehabilitation	FA INGERSOLL ST - Ferrand Estates	2,100	1	Project	Imminent Rehabilitation	GRANDVILLE	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	386
46		**LVD Lines Rehabilitation Subtotal (Imminent Rehabilitation)**	**6,665**						
47		**Imminent Rehabilitation Total**	**9,413**						
48	LVD Lines Rehabilitation	Modem Replacements	**2,998**	800	Modems	Modem Replacement	STATEWIDE	Avoid Obsolescence	
49	LVD Lines Rehabilitation	Meter Voltage Anomalies	**11,553**	N/A			STATEWIDE	Regulatory Compliance	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
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Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FLRE SUBSF COWAN LAKE RAMSDELL 1440	32	1	Project	Subsurface Transformer Replacement	COURTLAND	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
2	LVD Lines Rehabilitation	FLRE SUBSF MARNE MARNE 1140	25	1	Project	Subsurface Transformer Replacement	WRIGHT	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
3	LVD Lines Rehabilitation	FLRE SUBSF STANDALE STANDALE 1401	27	1	Project	Subsurface Transformer Replacement	GRAND RAPIDS	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
4	LVD Lines Rehabilitation	FLRE SUBSF STANDALE STANDALE 1402	28	1	Project	Subsurface Transformer Replacement	GRAND RAPIDS	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
5	LVD Lines Rehabilitation	FLRE SUBSF MARNE MARNE 1141	25	1	Project	Subsurface Transformer Replacement	WRIGHT	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
6	LVD Lines Rehabilitation	FLRE SUBSF MARNE MARNE 1142	30	1	Project	Subsurface Transformer Replacement	WRIGHT	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
7	LVD Lines Rehabilitation	FLRE SUBSF CASCADE THORNCREST 4340	45	1	Project	Subsurface Transformer Replacement	LOWELL	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
8	LVD Lines Rehabilitation	FLRE SUBSF CASCADE THORNCREST 4342	42	1	Project	Subsurface Transformer Replacement	LOWELL	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
9	LVD Lines Rehabilitation	FLRE SUBSF PETTIS ROAD HONEY CREEK 1241	52	1	Project	Subsurface Transformer Replacement	ADA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
10	LVD Lines Rehabilitation	FLRE SUBSF PETTIS ROAD HONEY CREEK 1240	51	1	Project	Subsurface Transformer Replacement	ADA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
11	LVD Lines Rehabilitation	FLRE SUBSF ROCKFORD SUMMIT 3440	34	1	Project	Subsurface Transformer Replacement	ROCKFORD	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
12	LVD Lines Rehabilitation	FLRE SUBSF CASCADE THORNCREST 4341	52	1	Project	Subsurface Transformer Replacement	LOWELL	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
13	LVD Lines Rehabilitation	FLRE SUBSF EASTWOOD_EAST 1073263880	1,010	1	Project	Subsurface Transformer Replacement	KALAMAZOO	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	210
14	LVD Lines Rehabilitation	FLRE SUBSF BOMAN COUTANT LCP 431 1024587821	198	1	Project	Subsurface Transformer Replacement	FLINT	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	63
15	LVD Lines Rehabilitation	FLRE SUBSF PIGEON LAKE-PIGEON 1073354393	135	1	Project	Subsurface Transformer Replacement	OTTAWA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	55
16	LVD Lines Rehabilitation	FLRE SUBSF BUCHANAN-SANDY SHORES 1073342894	432	1	Project	Subsurface Transformer Replacement	OTTAWA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	100
17	LVD Lines Rehabilitation	FLRE SUBSF VIRGINIA PARK-CASTLE 1073342867	26	1	Project	Subsurface Transformer Replacement	ALLEGAN	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	1
18	LVD Lines Rehabilitation	FLRE SUBSF COLLEGE PARK CARLETON 1171	16	1	Project	Subsurface Transformer Replacement	ADRIAN	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
19	LVD Lines Rehabilitation	FLRE SUBSF HURON TWO MILE 3141	18	1	Project	Subsurface Transformer Replacement	BANGOR	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
20	LVD Lines Rehabilitation	FLRE SUBSF HURON TWO MILE 3142	25	1	Project	Subsurface Transformer Replacement	BANGOR	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
21	LVD Lines Rehabilitation	FLRE SUBSF HURON TWO MILE 3240	17	1	Project	Subsurface Transformer Replacement	BANGOR	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
22	LVD Lines Rehabilitation	FLRE SUBSF HURON TWO MILE 3140	25	1	Project	Subsurface Transformer Replacement	BANGOR	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
23	LVD Lines Rehabilitation	FLRE SUBSF FRANKFORT CRYSTALLIA 4341	30	1	Project	Subsurface Transformer Replacement	FRANKFORT	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
24	LVD Lines Rehabilitation	FLRE SUBSF CADILLAC HOSPITAL 3344	25	1	Project	Subsurface Transformer Replacement	CADILLAC	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
25	LVD Lines Rehabilitation	FLRE SUBSF CADILLAC HOSPITAL 3345	25	1	Project	Subsurface Transformer Replacement	CADILLAC	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
26	LVD Lines Rehabilitation	FLRE SUBSF CADILLAC HOSPITAL 2242	25	1	Project	Subsurface Transformer Replacement	CADILLAC	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
27	LVD Lines Rehabilitation	FLRE SUBSF CADILLAC HOSPITAL 3341	26	1	Project	Subsurface Transformer Replacement	CADILLAC	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
28	LVD Lines Rehabilitation	FLRE SUBSF BOMAN COUTANT 3140	16	1	Project	Subsurface Transformer Replacement	FLUSHING	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
29	LVD Lines Rehabilitation	FLRE SUBSF HOGSBACK SYCAMORE 2441	18	1	Project	Subsurface Transformer Replacement	DELHI	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
30	LVD Lines Rehabilitation	FLRE SUBSF HOGSBACK SYCAMORE 2442	25	1	Project	Subsurface Transformer Replacement	DELHI	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
31	LVD Lines Rehabilitation	FLRE SUBSF SPRING LAKE COUNTRY CLUB 2240	17	1	Project	Subsurface Transformer Replacement	SPRING LAKE	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
32	LVD Lines Rehabilitation	FLRE SUBSF JOHNSON CEDAR 1340	25	1	Project	Subsurface Transformer Replacement	ROBINSON	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
33	LVD Lines Rehabilitation	FLRE SUBSF BECKER BEAR CREEK 1240	30	1	Project	Subsurface Transformer Replacement	MUSKEGON	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
34	LVD Lines Rehabilitation	FLRE SUBSF BECKER BEAR CREEK 1242	25	1	Project	Subsurface Transformer Replacement	MUSKEGON	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
35	LVD Lines Rehabilitation	FLRE SUBSF BECKER BEAR CREEK 1241	25	1	Project	Subsurface Transformer Replacement	MUSKEGON	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
36	LVD Lines Rehabilitation	FLRE SUBSF WHITEHALL ALICE 1442	25	1	Project	Subsurface Transformer Replacement	WHITEHALL	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
37	LVD Lines Rehabilitation	FLRE SUBSF SEIDEL BROCKWAY 1359	27	1	Project	Subsurface Transformer Replacement	SAGINAW	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
38	LVD Lines Rehabilitation	FLRE SUBSF SEIDEL BROCKWAY 1251	28	1	Project	Subsurface Transformer Replacement	SAGINAW	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
39	LVD Lines Rehabilitation	FLRE SUBSF SEIDEL BROCKWAY 1360	25	1	Project	Subsurface Transformer Replacement	SAGINAW	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
40	LVD Lines Rehabilitation	FLRE SUBSF M.A.E. LINCOLN ROAD 4475	30	1	Project	Subsurface Transformer Replacement	MONROE	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
41	LVD Lines Rehabilitation	FLRE SUBSF LEELANAU OMENA BAY 4141	45	1	Project	Subsurface Transformer Replacement	LEELANAU	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
42	LVD Lines Rehabilitation	FLRE SUBSF LEELANAU OMENA BAY 4142	42	1	Project	Subsurface Transformer Replacement	LEELANAU	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
43	LVD Lines Rehabilitation	FLRE SUBSF LEELANAU OMENA BAY 1140	25	1	Project	Subsurface Transformer Replacement	LEELANAU	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
44	LVD Lines Rehabilitation	FLRE SUBSF LEELANAU OMENA BAY 1141	25	1	Project	Subsurface Transformer Replacement	LEELANAU	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
45	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3440	17	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
46	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3442	25	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
47	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 4341	30	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
48	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 2441	25	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
49	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3441	25	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
50	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3443	25	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
51	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3444	27	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
52	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3440	28	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
53	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 4240	25	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
54	LVD Lines Rehabilitation	FLRE SUBSF PENINSULA MAPLETON 3442	25	1	Project	Subsurface Transformer Replacement	PENINSULA	Deteriorated Underground Conductor/ Equipment Replacement ; Customers	3
54		**Sub-Surface Total**	**3,181**						
54		**LVD Lines Rehabilitation Total**	**27,145**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Resiliency	BASS LAKE/KISTLER/168	440	1.1	miles	Overhead to Underground	Mason Co.	Customer-outage-minutes avoided	49,426
2		BLUE STAR/PIER COVE/622	480	1.2	miles	Overhead to Underground	Allegan Co.	Customer-outage-minutes avoided	35,686
3		BUTTERFIELD/LINDEN/60	480	1.2	miles	Overhead to Underground	Newaygo Co.	Customer-outage-minutes avoided	25,080
4		CONCORD/SWAINS LAKE/581	400	1.0	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	28,866
5		DEAN ROAD/HARTLAND/951	800	2.0	miles	Overhead to Underground	Livingston Co.	Customer-outage-minutes avoided	75,471
6		ELEVENTH STREET/BASELINE/268	1,120	2.8	miles	Overhead to Underground	Kalamazoo Co.	Customer-outage-minutes avoided	53,410
7		HALLS LAKE/HALLS LAKE/173	920	2.3	miles	Overhead to Underground	Calhoun Co.	Customer-outage-minutes avoided	61,463
8		LAKE LEANN/LAKE LEANN/282	400	1.0	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	47,318
9		MERSON/MERSON/412	800	2.0	miles	Overhead to Underground	Allegan Co.	Customer-outage-minutes avoided	64,148
10		PECK ROAD/M-91/473	840	2.1	miles	Overhead to Underground	Montcalm Co.	Customer-outage-minutes avoided	98,091
11		PENINSULA/MAPLETON/124	440	1.1	miles	Overhead to Underground	Grand Traverse Co.	Customer-outage-minutes avoided	55,599
12		SPRUCE ROAD/EAST BAY/693	200	0.5	miles	Overhead to Underground	Alcona Co.	Customer-outage-minutes avoided	51,908
13		SPRUCE ROAD/EAST BAY/868	280	0.7	miles	Overhead to Underground	Alcona Co.	Customer-outage-minutes avoided	37,643
14		YORKVILLE/HIGHLAND PARK/182	440	1.1	miles	Overhead to Underground	Kalamazoo Co.	Customer-outage-minutes avoided	47,581
15		BALCOM/BANKERS/736	600	1.5	miles	Overhead to Underground	Hillsdale Co.	Customer-outage-minutes avoided	30,819
16		BLACKMAN/SANDSTONE/404	1,080	2.7	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	181,206
17		KOLASSA/MATTESON/187	320	0.8	miles	Overhead to Underground	Branch Co.	Customer-outage-minutes avoided	47,956
18		TRUFANT/GOWEN/847	440	1.1	miles	Overhead to Underground	Kent Co.	Customer-outage-minutes avoided	64,962
19		CASCO/HAWKHEAD/516	280	0.7	miles	Overhead to Underground	Allegan Co.	Customer-outage-minutes avoided	22,005
20		HANOVER/PULASKI/532	1,680	4.2	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	117,839
21		LAKE LEANN/LAKE LEANN/159	480	1.2	miles	Overhead to Underground	Hillsdale Co.	Customer-outage-minutes avoided	49,381
22		WHITTEMORE/SAND LAKE/28	360	0.9	miles	Overhead to Underground	Iosco Co.	Customer-outage-minutes avoided	436,554
23		ALGER/SKIDWAY/606	600	1.5	miles	Overhead to Underground	Ogemaw Co.	Customer-outage-minutes avoided	61,365
24		ALGER/SKIDWAY/819	320	0.8	miles	Overhead to Underground	Ogemaw Co.	Customer-outage-minutes avoided	35,483
25		BRICKER/STOREY ROAD/228	2,040	5.1	miles	Overhead to Underground	Kent Co.	Customer-outage-minutes avoided	86,953
26		HARVARD LAKE/HARVARD LAKE/986	2,120	5.3	miles	Overhead to Underground	Kent Co.	Customer-outage-minutes avoided	92,753
27		SHERMAN/SHERMAN/304	1,480	3.7	miles	Overhead to Underground	Iosco Co.	Customer-outage-minutes avoided	50,822
28		BROOKLYN/BROOKLYN/811	160	0.4	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	30,448
29		BENNINGTON	2,483	1	Project	Resiliency - Fractionalization	Shiawasee Co.	Customer-outage-minutes avoided	76,750
30		EAGLE	4,668	0	Project	Resiliency - Fractionalization	Ottawa Co.	Customer-outage-minutes avoided	
31		MOBILE 27	4,496	1	Project	Resiliency - Fractionalization	Statewide	Customer-outage-minutes avoided	
32		EGLE GRANT - Undergrounding Services - Grand Rapids	1,310	3	Projects	Undergrounding of Services and Secondary Improvements in DACs	Grand Rapids	Improved MIEJ Reliability; Customers	54
33		EGLE GRANT - Undergrounding Services - Flint	1,259	2	Projects	Undergrounding of Services and Secondary Improvements in DACs	Flint	Improved MIEJ Reliability; Customers	53
34		EGLE GRANT - Undergrounding Services - Kalamazoo	1,549	4	Projects	Undergrounding of Services and Secondary Improvements in DACs	Kalamazoo	Improved MIEJ Reliability; Customers	72
35		**Resiliency Total**	**35,765**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Vulnerable Communities								
1	Resiliency	HARRIET_HARRIET TO MILBOURNE_DUPONT	2,200	2.2	miles	Resiliency - MIEJ Hardening	Genesee	Customer-outage-minutes avoided	201,006
2		EASTWOOD_TEXEL TO AMPERSEE_BORGESS	2,300	2.3	miles	Resiliency - MIEJ Hardening	Kalamazoo	Customer-outage-minutes avoided	299,815
3		MOSEL_ALLEN TO RAVINE_PATTERSON	2,300	2.3	miles	Resiliency - MIEJ Hardening	Kalamazoo	Customer-outage-minutes avoided	270,203
4		DEWEY_SEATING TO WEALTHY ST_NORTHWEST	2,300	2.3	miles	Resiliency - MIEJ Hardening	Kent Co.	Customer-outage-minutes avoided	632,017
5		HASKELITE_3 MILE TO FOURMILE_WALKENT	3,000	3.0	miles	Resiliency - MIEJ Hardening	Kent Co.	Customer-outage-minutes avoided	487,640
6		WEALTHY ST_BUTTERWORTH TO MAYNARD_BESTWA	3,300	3.3	miles	Resiliency - MIEJ Hardening	Kent Co.	Customer-outage-minutes avoided	79,265
7		EAST MUSKEGON_Q.LINE ROAD TO GETTY_MARQ.	2,000	2.8	miles	Resiliency - MIEJ Hardening	Muskegon Co.	Customer-outage-minutes avoided	255,841
8		MAPLE GROVE_SUMMITAVE TO MUSK.H_HEIGHTS	2,140	2.6	miles	Resiliency - MIEJ Hardening	Muskegon Co.	Customer-outage-minutes avoided	187,951
9		MONA LAKE_AIRPORT TO BROADWAY_PHILLIP	2,900	3.3	miles	Resiliency - MIEJ Hardening	Muskegon Co.	Customer-outage-minutes avoided	167,799
10		COLLEGE PARK_MADISON TO CADMUS_WINTER	1,600	1.8	miles	Resiliency - MIEJ Hardening	Lenawee	Customer-outage-minutes avoided	1,649,932
11		LIBERTY_LIBERTY TO GOGUAC_LAKEVIEW	2,000	2.2	miles	Resiliency - MIEJ Hardening	Calhoun	Customer-outage-minutes avoided	160,153
12		MAUMEE_MAPLE ST TO COLLEGEPARK_RIVERSIDE	1,500	1.9	miles	Resiliency - MIEJ Hardening	Lenawee	Customer-outage-minutes avoided	483,186
13		ROBERTS ST_LEROY STREET TO OAK ST_STATE	2,460	2.1	miles	Resiliency - MIEJ Hardening	Jackson	Customer-outage-minutes avoided	211,673
14		**Vulnerable Communities Total**	**30,000**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE BELL ROAD/ALBEE LCP 989	601	1	Project	Overloaded Equipment Upgrades	TAYMOUTH TOWNSHIP	Overload Failure Reduction; Customers	1276
2	LVD Lines Capacity	DARE BLUE STAR/PIER COVE LCP 613	619	1	Project	Overloaded Equipment Upgrades	GANGES TOWNSHIP	Overload Failure Reduction; Customers	131
3	LVD Lines Capacity	DARE BRISTOL_MILLER LCP Sub	488	1	Project	Overloaded Equipment Upgrades	SAGINAW TOWNSHIP	Overload Failure Reduction; Customers	1020
4	LVD Lines Capacity	DARE CARY-LKCOLUMBIA-561-DIVERSY AT HEWIT	3	1	Project	Overloaded Equipment Upgrades	COLUMBIA TOWNSHIP	Overload Failure Reduction; Customers	153
5	LVD Lines Capacity	DARE CONVIS CONVIS LCP 336	9	1	Project	Overloaded Equipment Upgrades	CONVIS TOWNSHIP	Overload Failure Reduction; Customers	32
6	LVD Lines Capacity	DARE PORTSMOUTH/BLUMFIELD LCP 255 PART 2	441	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	386
7	LVD Lines Capacity	DARE ROCKFORD_SUMMIT LCP-686	23	1	Project	Overloaded Equipment Upgrades	ROCKFORD	Overload Failure Reduction; Customers	99
8	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT5	666	1	Project	Sub Capacity-associated Line Work	SPARTA	Overload Failure Reduction; Customers	153
9	LVD Lines Capacity	DARE21 LEFFINGWELL/BRADFORD EB RECON PT2	316	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	704
10	LVD Lines Capacity	DARE21 PARMA BALDWIN	32	1	Project	Overloaded Equipment Upgrades	PARMA TOWNSHIP	Overload Failure Reduction; Customers	1356
11	LVD Lines Capacity	DARE24 Fine Lake - Dowling	94	1	Project	Overloaded Equipment Upgrades	JOHNSTOWN TOWNSHIP	Overload Failure Reduction; Customers	471
12	LVD Lines Capacity	AGNEW_WEYBURN LCP 945	90	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN TOWNSHIP	Overload Failure Reduction; Customers	924
13	LVD Lines Capacity	ALCONA DAM_GLENNIE LCP	700	1	Project	Overloaded Equipment Upgrades	CURTIS TOWNSHIP	Overload Failure Reduction; Customers	903
14	LVD Lines Capacity	ALDER CREEK_EAST LEROY LCP 867	130	1	Project	Overloaded Equipment Upgrades	ATHENS TOWNSHIP	Overload Failure Reduction; Customers	47
15	LVD Lines Capacity	ALLENDALE_BLENDON LCP 071	350	1	Project	Overloaded Equipment Upgrades	ALLENDALE TOWNSHIP	Overload Failure Reduction; Customers	169
16	LVD Lines Capacity	ALLENDALE_BLENDON LCP 074	90	1	Project	Overloaded Equipment Upgrades	ALLENDALE TOWNSHIP	Overload Failure Reduction; Customers	169
17	LVD Lines Capacity	ALLENDALE_BLENDON LCP 542	85	1	Project	Overloaded Equipment Upgrades	ALLENDALE TOWNSHIP	Overload Failure Reduction; Customers	86
18	LVD Lines Capacity	ALTO_MCCORDS LCP 564	85	1	Project	Overloaded Equipment Upgrades	BOWNE TOWNSHIP	Overload Failure Reduction; Customers	20
19	LVD Lines Capacity	AU GRES_POINT LOOK-OUT LCP 553	130	1	Project	Overloaded Equipment Upgrades	WHITNEY TOWNSHIP	Overload Failure Reduction; Customers	79
20	LVD Lines Capacity	AU GRES_POINT LOOK-OUT LCP 555	210	1	Project	Overloaded Equipment Upgrades	WHITNEY TOWNSHIP	Overload Failure Reduction; Customers	79
21	LVD Lines Capacity	AU GRES_POINT LOOK-OUT LCP 559	85	1	Project	Overloaded Equipment Upgrades	WHITNEY TOWNSHIP	Overload Failure Reduction; Customers	33
22	LVD Lines Capacity	AU GRES_POINT LOOK-OUT LCP 578	85	1	Project	Overloaded Equipment Upgrades	WHITNEY TOWNSHIP	Overload Failure Reduction; Customers	46
23	LVD Lines Capacity	BACKUS_SPRINGBROOK LCP 229	210	1	Project	Overloaded Equipment Upgrades	DENTON TOWNSHIP	Overload Failure Reduction; Customers	399
24	LVD Lines Capacity	BACKUS_SPRINGBROOK LCP 251	90	1	Project	Overloaded Equipment Upgrades	DENTON TOWNSHIP	Overload Failure Reduction; Customers	382
25	LVD Lines Capacity	BACKUS_SPRINGBROOK LCP 465	240	1	Project	Overloaded Equipment Upgrades	DENTON TOWNSHIP	Overload Failure Reduction; Customers	1985
26	LVD Lines Capacity	BACKUS_SPRINGBROOK LCP 865	130	1	Project	Overloaded Equipment Upgrades	MARKEY TOWNSHIP	Overload Failure Reduction; Customers	262
27	LVD Lines Capacity	BALZER_SANDERS LCP 143	130	1	Project	Overloaded Equipment Upgrades	AURELIUS TOWNSHIP	Overload Failure Reduction; Customers	45
28	LVD Lines Capacity	BAYBERRY_PLEASANT HILL LCP 325	90	1	Project	Overloaded Equipment Upgrades	CITY OF WYOMING	Overload Failure Reduction; Customers	231
29	LVD Lines Capacity	BEAVER_CRUMP LCP 285	85	1	Project	Overloaded Equipment Upgrades	LARKIN TOWNSHIP	Overload Failure Reduction; Customers	55
30	LVD Lines Capacity	BEECHER_ANDERSON LCP	700	1	Project	Overloaded Equipment Upgrades	CITY OF ADRIAN	Overload Failure Reduction; Customers	383
31	LVD Lines Capacity	BEERS_BALDWIN ROAD LCP 301	90	1	Project	Overloaded Equipment Upgrades	GAINES TOWNSHIP	Overload Failure Reduction; Customers	119
32	LVD Lines Capacity	BEERS_BALDWIN ROAD LCP 801	85	1	Project	Overloaded Equipment Upgrades	GAINES TOWNSHIP	Overload Failure Reduction; Customers	44
33	LVD Lines Capacity	BENNETT_KNOB HILL LCP 001	30	1	Project	Overloaded Equipment Upgrades	MERIDIAN TOWNSHIP	Overload Failure Reduction; Customers	1002
34	LVD Lines Capacity	BLUE WATER_TOWNSEND ROAD LCP 741	130	1	Project	Overloaded Equipment Upgrades	BINGHAM TOWNSHIP	Overload Failure Reduction; Customers	102
35	LVD Lines Capacity	BOMAN_DELAND LCP 168	85	1	Project	Overloaded Equipment Upgrades	MT MORRIS TOWNSHIP	Overload Failure Reduction; Customers	1
36	LVD Lines Capacity	BOON ROAD_ROUND LAKE LCP 773	75	1	Project	Overloaded Equipment Upgrades	HARING TOWNSHIP	Overload Failure Reduction; Customers	173
37	LVD Lines Capacity	BRECKENRIDGE_WHEELER LCP 709	85	1	Project	Overloaded Equipment Upgrades	WHEELER TOWNSHIP	Overload Failure Reduction; Customers	1
38	LVD Lines Capacity	BREEDSVILLE_BREEDSVILLE LCP 052	85	1	Project	Overloaded Equipment Upgrades	COLUMBIA TOWNSHIP	Overload Failure Reduction; Customers	45
39	LVD Lines Capacity	BREEDSVILLE_BREEDSVILLE LCP 863	130	1	Project	Overloaded Equipment Upgrades	COLUMBIA TOWNSHIP	Overload Failure Reduction; Customers	70
40	LVD Lines Capacity	BURR OAK_DOUGLAS LCP 929	130	1	Project	Overloaded Equipment Upgrades	FAWN RIVER TOWNSHIP	Overload Failure Reduction; Customers	48
41	LVD Lines Capacity	CAMELOT LAKE_COLEMAN LCP 602	85	1	Project	Overloaded Equipment Upgrades	GREENDALE TOWNSHIP	Overload Failure Reduction; Customers	104
42	LVD Lines Capacity	CAMELOT LAKE_COLEMAN LCP 802	90	1	Project	Overloaded Equipment Upgrades	GREENDALE TOWNSHIP	Overload Failure Reduction; Customers	159
43	LVD Lines Capacity	CAMELOT LAKE_LOOMIS LCP 468	130	1	Project	Overloaded Equipment Upgrades	CHIPPEWA TOWNSHIP	Overload Failure Reduction; Customers	61
44	LVD Lines Capacity	CANNONSBURG_WEST CANNON LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	2176
45	LVD Lines Capacity	CANNONSBURG_WEST CANNON LCP	90	1	Project	Overloaded Equipment Upgrades	CANNON TOWNSHIP	Overload Failure Reduction; Customers	777
46	LVD Lines Capacity	CANNONSBURG_WEST CANNON LCP 377	90	1	Project	Overloaded Equipment Upgrades	CANNON TOWNSHIP	Overload Failure Reduction; Customers	192
47	LVD Lines Capacity	DARE CARSON CITY_BUTTERNUT LCP SUB	104	1	Project	Overloaded Equipment Upgrades	CARSON CITY	Overload Failure Reduction; Customers	406
48	LVD Lines Capacity	CARSON CITY_BUTTERNUT LCP 635	210	1	Project	Overloaded Equipment Upgrades	BLOOMER TOWNSHIP	Overload Failure Reduction; Customers	253
49	LVD Lines Capacity	CARSON CITY_BUTTERNUT LCP 706	85	1	Project	Overloaded Equipment Upgrades	BUSHNELL TOWNSHIP	Overload Failure Reduction; Customers	60
50	LVD Lines Capacity	CASCADE_PEACE STREET LCP 324	240	1	Project	Overloaded Equipment Upgrades	CASCADE TOWNSHIP	Overload Failure Reduction; Customers	677
51	LVD Lines Capacity	CHAPIN_MARION LCP 933	210	1	Project	Overloaded Equipment Upgrades	MARION TOWNSHIP	Overload Failure Reduction; Customers	83
52	LVD Lines Capacity	CHARLOTTE_FOOTE STREET LCP 075	85	1	Project	Overloaded Equipment Upgrades	CARMEL TOWNSHIP	Overload Failure Reduction; Customers	75
53	LVD Lines Capacity	CHEBOYGAN_ALVERNO LCP 760	130	1	Project	Overloaded Equipment Upgrades	BENTON TOWNSHIP	Overload Failure Reduction; Customers	164
54	LVD Lines Capacity	CHESTER_MORRELL LCP 314	130	1	Project	Overloaded Equipment Upgrades	CHESTER TOWNSHIP	Overload Failure Reduction; Customers	120
55	LVD Lines Capacity	CHICAGO_CHICAGO LCP 431	240	1	Project	Overloaded Equipment Upgrades	GEORGETOWN TOWNSHIP	Overload Failure Reduction; Customers	587
56	LVD Lines Capacity	CLARE_FARWELL LCP 291	130	1	Project	Overloaded Equipment Upgrades	VERNON TOWNSHIP	Overload Failure Reduction; Customers	154
57	LVD Lines Capacity	CLEAR LAKE_WATERLOO LCP 373	130	1	Project	Overloaded Equipment Upgrades	WATERLOO TOWNSHIP	Overload Failure Reduction; Customers	31
58	LVD Lines Capacity	CLEAR LAKE_WATERLOO LCP 386	85	1	Project	Overloaded Equipment Upgrades	LYNDON TOWNSHIP	Overload Failure Reduction; Customers	24
59	LVD Lines Capacity	CLEAR LAKE_WATERLOO LCP 884	85	1	Project	Overloaded Equipment Upgrades	LYNDON TOWNSHIP	Overload Failure Reduction; Customers	27
60	LVD Lines Capacity	CLEAR LAKE_WATERLOO LCP 905	130	1	Project	Overloaded Equipment Upgrades	WATERLOO TOWNSHIP	Overload Failure Reduction; Customers	40
61	LVD Lines Capacity	CLYDE ROAD_GLENN ROAD LCP 338	130	1	Project	Overloaded Equipment Upgrades	CITY OF IONIA	Overload Failure Reduction; Customers	130
62		**LVD Lines Capacity Subtotal**	**11,290**						

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	Capacity								
1	LVD Lines Capacity	DARE08 Ridge Rd Cavanaugh Lk	254	1	Project	Overloaded Equipment Upgrades	SYLVAN TOWNSHIP	Overload Failure Reduction; Customers	84
2	LVD Lines Capacity	COCHRAN_KALAMO LCP 623	35	1	Project	Overloaded Equipment Upgrades	EATON TOWNSHIP	Overload Failure Reduction; Customers	41
3	LVD Lines Capacity	COCHRAN_KALAMO LCP 628	105	1	Project	Overloaded Equipment Upgrades	CARMEL TOWNSHIP	Overload Failure Reduction; Customers	105
4	LVD Lines Capacity	COLON_PALMER LCP 757	30	1	Project	Overloaded Equipment Upgrades	COLON TOWNSHIP	Overload Failure Reduction; Customers	527
5	LVD Lines Capacity	COLUMBIA_COLUMBIA LCP 224	240	1	Project	Overloaded Equipment Upgrades	CITY OF BATTLE CREEK	Overload Failure Reduction; Customers	1020
6	LVD Lines Capacity	CONVIS_CONVIS LCP	700	1	Project	Overloaded Equipment Upgrades	CONVIS TOWNSHIP	Overload Failure Reduction; Customers	1
7	LVD Lines Capacity	COWAN LAKE_RAMSDELL LCP 656	130	1	Project	Overloaded Equipment Upgrades	CANNON TOWNSHIP	Overload Failure Reduction; Customers	85
8	LVD Lines Capacity	DEAN ROAD_SHANNON LAKE LCP 156	130	1	Project	Overloaded Equipment Upgrades	ARGENTINE TOWNSHIP	Overload Failure Reduction; Customers	124
9	LVD Lines Capacity	DEER LAKE_CRANBERRY LAKE LCP 112	85	1	Project	Overloaded Equipment Upgrades	HAYES TOWNSHIP	Overload Failure Reduction; Customers	302
10	LVD Lines Capacity	DEER LAKE_CRANBERRY LAKE LCP 333	85	1	Project	Overloaded Equipment Upgrades	HAYES TOWNSHIP	Overload Failure Reduction; Customers	187
11	LVD Lines Capacity	DEWITT_GENEVA LAKE LCP 070	90	1	Project	Overloaded Equipment Upgrades	CITY OF DEWITT	Overload Failure Reduction; Customers	663
12	LVD Lines Capacity	DIMONDALE_M-99 LCP 778	90	1	Project	Overloaded Equipment Upgrades	WINDSOR TOWNSHIP	Overload Failure Reduction; Customers	424
13	LVD Lines Capacity	DONTZ ROAD_PORTAGE LCP	30	1	Project	Overloaded Equipment Upgrades	MANISTEE TOWNSHIP	Overload Failure Reduction; Customers	1
14	LVD Lines Capacity	DURAND_CITY LCP 534	85	1	Project	Overloaded Equipment Upgrades	VERNON TOWNSHIP	Overload Failure Reduction; Customers	8
15	LVD Lines Capacity	EAST GRANT_MUD FLAT LCP 120	75	1	Project	Overloaded Equipment Upgrades	GRANT TOWNSHIP	Overload Failure Reduction; Customers	123
16	LVD Lines Capacity	EAST JACKSON_TROJAN LCP 577	90	1	Project	Overloaded Equipment Upgrades	LEONI TOWNSHIP	Overload Failure Reduction; Customers	95
17	LVD Lines Capacity	EAST JORDAN_IRONTON LCP 479	85	1	Project	Overloaded Equipment Upgrades	EVELINE TOWNSHIP	Overload Failure Reduction; Customers	226
18	LVD Lines Capacity	EAST JORDAN_IRONTON LCP 479	85	1	Project	Overloaded Equipment Upgrades	EVELINE TOWNSHIP	Overload Failure Reduction; Customers	226
19	LVD Lines Capacity	EDMORE_SIX LAKES LCP 266	90	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	150
20	LVD Lines Capacity	EDMORE_SIX LAKES LCP 356	130	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	147
21	LVD Lines Capacity	EDMORE_SIX LAKES LCP 363	30	1	Project	Overloaded Equipment Upgrades	HOME TOWNSHIP	Overload Failure Reduction; Customers	735
22	LVD Lines Capacity	EDMORE_SIX LAKES LCP 373	210	1	Project	Overloaded Equipment Upgrades	BELVIDERE TOWNSHIP	Overload Failure Reduction; Customers	153
23	LVD Lines Capacity	EIGHT POINT_LAKE GEORGE LCP 101	130	1	Project	Overloaded Equipment Upgrades	FREEMAN TOWNSHIP	Overload Failure Reduction; Customers	27
24	LVD Lines Capacity	EIGHT POINT_LAKE GEORGE LCP 105	210	1	Project	Overloaded Equipment Upgrades	FREEMAN TOWNSHIP	Overload Failure Reduction; Customers	66
25	LVD Lines Capacity	EIGHT POINT_LAKE GEORGE LCP 109	130	1	Project	Overloaded Equipment Upgrades	FREEMAN TOWNSHIP	Overload Failure Reduction; Customers	67
26	LVD Lines Capacity	EIGHT POINT_LAKE GEORGE LCP 860	130	1	Project	Overloaded Equipment Upgrades	FREEMAN TOWNSHIP	Overload Failure Reduction; Customers	158
27	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 303	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	62
28	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 305	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	157
29	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 384	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	133
30	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 436	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	20
31	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 5054	90	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	623
32	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 529	130	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	628
33	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 531	210	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	628
34	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 534	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	98
35	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 541	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	120
36	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 564	130	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	159
37	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 565	85	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	159
38	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 583	130	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	35
39	LVD Lines Capacity	EIGHT POINT_LUDINGTON LCP 751	378	1	Project	Overloaded Equipment Upgrades	GARFIELD TOWNSHIP	Overload Failure Reduction; Customers	147
40	LVD Lines Capacity	DARE EAST TAWAS_LINCOLN STREET 805	25	1	Project	Overloaded Equipment Upgrades	BALDWIN TOWNSHIP	Overload Failure Reduction; Customers	309
41	LVD Lines Capacity	DARE19 Trufant_Hunter Lake	112	1	Project	Overloaded Equipment Upgrades	PINE TOWNSHIP	Overload Failure Reduction; Customers	93
42	LVD Lines Capacity	ELLSWORH_ELLS 09 LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	887
43	LVD Lines Capacity	ELLSWORTH_CIVIC LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	195
44	LVD Lines Capacity	ELSIE_CARLAND LCP 495	130	1	Project	Overloaded Equipment Upgrades	DUPLAIN TOWNSHIP	Overload Failure Reduction; Customers	174
45	LVD Lines Capacity	FAIRBANKS_POST OFFICE LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	191
46	LVD Lines Capacity	FAIRBANKS_WALTERS LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	498
47	LVD Lines Capacity	FLETCHER_ODEN LCP 064	85	1	Project	Overloaded Equipment Upgrades	TUSCARORA TOWNSHIP	Overload Failure Reduction; Customers	179
48	LVD Lines Capacity	FOOTE HYDRO_DISTRIBUTION LCP 005	85	1	Project	Overloaded Equipment Upgrades	OSCODA TOWNSHIP	Overload Failure Reduction; Customers	56
49	LVD Lines Capacity	FOUR MILE_CORDES LCP	750	1	Project	Overloaded Equipment Upgrades	ALPINE TOWNSHIP	Overload Failure Reduction; Customers	504
50	LVD Lines Capacity	FOUR MILE_GREENRIDGE LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	4375
51	LVD Lines Capacity	FOURTEENTH STREET_TOBIAS STREET LCP 763	85	1	Project	Overloaded Equipment Upgrades	CITY OF FLINT	Overload Failure Reduction; Customers	51
52	LVD Lines Capacity	FROST_LONG LAKE LCP	700	1	Project	Overloaded Equipment Upgrades	FROST TOWNSHIP	Overload Failure Reduction; Customers	463
53	LVD Lines Capacity	GOGUAC_GOGUAC LCP 7170	85	1	Project	Overloaded Equipment Upgrades	CITY OF BATTLE CREEK	Overload Failure Reduction; Customers	38
54	LVD Lines Capacity	GOODALE_HUBBARD LCP 373	90	1	Project	Overloaded Equipment Upgrades	BEDFORD TOWNSHIP	Overload Failure Reduction; Customers	220
55	LVD Lines Capacity	GOODALE_ROOSEVELT LCP	700	1	Project	Overloaded Equipment Upgrades	CITY OF BATTLE CREEK	Overload Failure Reduction; Customers	1166
56	LVD Lines Capacity	GRAND LEDGE_ACADEMY LCP 751	210	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND LEDGE	Overload Failure Reduction; Customers	786
57	LVD Lines Capacity	GREENWOOD_RAU ROAD LCP 865	130	1	Project	Overloaded Equipment Upgrades	EDWARDS TOWNSHIP	Overload Failure Reduction; Customers	272
58	LVD Lines Capacity	HARLEM_QUINCY STREET LCP	750	1	Project	Overloaded Equipment Upgrades	HOLLAND TOWNSHIP	Overload Failure Reduction; Customers	305
59	LVD Lines Capacity	HARLEM_QUINCY STREET LCP	750	1	Project	Overloaded Equipment Upgrades	HOLLAND TOWNSHIP	Overload Failure Reduction; Customers	19
60	LVD Lines Capacity	HARLEM_QUINCY STREET LCP 967	85	1	Project	Overloaded Equipment Upgrades	HOLLAND TOWNSHIP	Overload Failure Reduction; Customers	164
61		**LVD Lines Capacity Subtotal**	**13,670**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 25 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE AGNEW_WEYBURN LCP 309	2	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	20
2	LVD Lines Capacity	DARE AGNEW_WEYBURN LCP 207	2	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	300
3	LVD Lines Capacity	DARE AGNEW_WEYBURN LCP 307	130	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	125
4	LVD Lines Capacity	DARE BAY HARBOR_DUNDEE LCP SUB UG CABLE	160	1	Project	Overloaded Equipment Upgrades	PETOSKEY	Overload Failure Reduction; Customers	448
5	LVD Lines Capacity	DARE_BIG PRAIRIE_OXBOW_LCP 915	50	1	Project	Overloaded Equipment Upgrades	BIG PRAIRIE	Overload Failure Reduction; Customers	334
6	LVD Lines Capacity	DARE BIL-MAR_POLK LCP 527	518	1	Project	Overloaded Equipment Upgrades	HOLLAND	Overload Failure Reduction; Customers	135
7	LVD Lines Capacity	DARE BLACK RIVER_FILLMORE LCP 264	1	1	Project	Overloaded Equipment Upgrades	ZEELAND	Overload Failure Reduction; Customers	21
8	LVD Lines Capacity	DARE19 BLUE STAR/PIER COVE LCP 619	339	1	Project	Overloaded Equipment Upgrades	SAUGATUCK	Overload Failure Reduction; Customers	131
9	LVD Lines Capacity	DARE BLUE STAR/PIER COVE LCP 613	400	1	Project	Overloaded Equipment Upgrades	SAUGATUCK	Overload Failure Reduction; Customers	131
10	LVD Lines Capacity	DARE BLUE STAR_GANGES LCP 893	43	1	Project	Overloaded Equipment Upgrades	GANGES TOWNSHIP	Overload Failure Reduction; Customers	86
11	LVD Lines Capacity	DARE BRADFORD_DISTRIBUTION LCP 588	108	1	Project	Overloaded Equipment Upgrades	LEE TOWNSHIP	Overload Failure Reduction; Customers	349
12	LVD Lines Capacity	DARE18 ENGLISHVILLE/ENGLISHVILLE PH EXT	450	1	Project	Overloaded Equipment Upgrades	SPARTA TOWNSHIP	Overload Failure Reduction; Customers	157
13	LVD Lines Capacity	DARE21 Levely_Albright LCP 250	166	1	Project	Overloaded Equipment Upgrades	BUCKEYE TOWNSHIP	Overload Failure Reduction; Customers	254
14	LVD Lines Capacity	DARE21 Levely_Allbright LCP 239	166	1	Project	Overloaded Equipment Upgrades	BUCKEYE TOWNSHIP	Overload Failure Reduction; Customers	54
15	LVD Lines Capacity	DARE21 Levely_Allbright LCP 665	335	1	Project	Overloaded Equipment Upgrades	BUCKEYE TOWNSHIP	Overload Failure Reduction; Customers	669
16	LVD Lines Capacity	DARE ONEKAMA_BEAR LAKE LCP 710	680	1	Project	Overloaded Equipment Upgrades	BEAR LAKE	Overload Failure Reduction; Customers	309
17	LVD Lines Capacity	DARE PORTSMOUTH/BLUMFIELD LCP 255	650	1	Project	Overloaded Equipment Upgrades	REESE TOWNSHIP	Overload Failure Reduction; Customers	386
18	LVD Lines Capacity	DARE PORTSMOUTH/INDIANTOWN LCP 133	1,100	1	Project	Overloaded Equipment Upgrades	REESE TOWNSHIP	Overload Failure Reduction; Customers	315
19	LVD Lines Capacity	DARE STARKS_HOMER LCP 429	371	1	Project	Overloaded Equipment Upgrades	MIDLAND TOWNSHIP	Overload Failure Reduction; Customers	342
20	LVD Lines Capacity	KINGSLEY_WALTON LCP 690	24	1	Project	Overloaded Equipment Upgrades	PARADISE TOWNSHIP	Overload Failure Reduction; Customers	155
21	LVD Lines Capacity	KIPP ROAD_M-36 LCP 5315	30	1	Project	Overloaded Equipment Upgrades	INGHAM TOWNSHIP	Overload Failure Reduction; Customers	78
22	LVD Lines Capacity	LAKE CITY_MOREY LCP 199	18	1	Project	Overloaded Equipment Upgrades	CALDWELL TOWNSHIP	Overload Failure Reduction; Customers	220
23	LVD Lines Capacity	DARE15 LOVEJOY-DEERFIELD PHI	1,220	1	Project	Overloaded Equipment Upgrades	COHOCTAH TOWNSHIP	Overload Failure Reduction; Customers	41
24	LVD Lines Capacity	LYON MANOR_TOWN HALL LCP 912	38	1	Project	Overloaded Equipment Upgrades	LYON TOWNSHIP	Overload Failure Reduction; Customers	783
25	LVD Lines Capacity	LYONS_COLLINS-RURAL LCP 338	130	1	Project	Overloaded Equipment Upgrades	LYONS TOWNSHIP	Overload Failure Reduction; Customers	131
26	LVD Lines Capacity	DARE21 PORTAGE SHAVER ROAD 917	354	1	Project	Overloaded Equipment Upgrades	PORTAGE	Overload Failure Reduction; Customers	1328
27	LVD Lines Capacity	DARE ALCONA DAM_GLENNIE 764	5	1	Project	Overloaded Equipment Upgrades	CURTIS TOWNSHIP	Overload Failure Reduction; Customers	51
28	LVD Lines Capacity	DARE ALCONA DAM_GLENNIE 768	18	1	Project	Overloaded Equipment Upgrades	CURTIS TOWNSHIP	Overload Failure Reduction; Customers	112
29	LVD Lines Capacity	DARE ALCONA DAM_GLENNIE 850	8	1	Project	Overloaded Equipment Upgrades	CURTIS TOWNSHIP	Overload Failure Reduction; Customers	184
30	LVD Lines Capacity	DARE ALCONA DAM_GLENNIE 909	7	1	Project	Overloaded Equipment Upgrades	CURTIS TOWNSHIP	Overload Failure Reduction; Customers	83
31	LVD Lines Capacity	DARE ALCONA DAM_GLENNIE 937	21	1	Project	Overloaded Equipment Upgrades	CURTIS TOWNSHIP	Overload Failure Reduction; Customers	106
32	LVD Lines Capacity	DARE ALDRICH-TRAVERSE LCP 242	69	1	Project	Overloaded Equipment Upgrades	FLINT	Overload Failure Reduction; Customers	720
33	LVD Lines Capacity	DARE AU GRES_AU GRES LCP 644	30	1	Project	Overloaded Equipment Upgrades	AU GRES TOWNSHIP	Overload Failure Reduction; Customers	93
34	LVD Lines Capacity	DARE BREEDSVILLE GRAND JUNCTION LCP 960	11	1	Project	Overloaded Equipment Upgrades	COLUMBIA TOWNSHIP	Overload Failure Reduction; Customers	24
35	LVD Lines Capacity	DARE CASINO_LEATON LCP 466	280	1	Project	Overloaded Equipment Upgrades	CHIPPEWA TOWNSHIP	Overload Failure Reduction; Customers	161
36	LVD Lines Capacity	DARE GREENBUSH_HARRISVILLE 402	20	1	Project	Overloaded Equipment Upgrades	HARRISVILLE TOWNSHIP	Overload Failure Reduction; Customers	54
37	LVD Lines Capacity	DARE HUBBARD LAKE_HUBBARD LAKE 600	11	1	Project	Overloaded Equipment Upgrades	HAWES TOWNSHIP	Overload Failure Reduction; Customers	319
38	LVD Lines Capacity	DARE LITCHFIELD_ADAMS RD LCP 557	2	1	Project	Overloaded Equipment Upgrades	LITCHFIELD TOWNSHIP	Overload Failure Reduction; Customers	8
39	LVD Lines Capacity	DARE LITCHFIELD_QUAKER LAKE LCP 522	7	1	Project	Overloaded Equipment Upgrades	BUTLER TOWNSHIP	Overload Failure Reduction; Customers	31
40	LVD Lines Capacity	DARE Maple City/Cedar LCP 060	265	1	Project	Overloaded Equipment Upgrades	MAPLE CITY	Overload Failure Reduction; Customers	127
41	LVD Lines Capacity	DARE STANDISH_STANDISH LCP 332	13	1	Project	Overloaded Equipment Upgrades	DEEP RIVER TOWNSHIP	Overload Failure Reduction; Customers	132
42	LVD Lines Capacity	DARE Starks Homer LCP 643	18	1	Project	Overloaded Equipment Upgrades	HOMER TOWNSHIP	Overload Failure Reduction; Customers	65
43	LVD Lines Capacity	DARE TWELFTH STREET_WESTFIELD LCP 084	5	1	Project	Overloaded Equipment Upgrades	TEXAS TOWNSHIP	Overload Failure Reduction; Customers	397
44	LVD Lines Capacity	DARE17 MIDDLETON/MIDDLETON LCP 954	11	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	215
45	LVD Lines Capacity	DARE NORTHPORT LIGHTHOUSE LCP 569	5	1	Project	Overloaded Equipment Upgrades	NORTHPORT	Overload Failure Reduction; Customers	59
46	LVD Lines Capacity	DARE NOBLE_WHITNEY LCP 513	98	1	Project	Overloaded Equipment Upgrades	WHITNEY TOWNSHIP	Overload Failure Reduction; Customers	419
47	LVD Lines Capacity	DARE N MUSKEGON DALTON LCP 285	166	1	Project	Overloaded Equipment Upgrades	LAKETON TOWNSHIP	Overload Failure Reduction; Customers	293
48	LVD Lines Capacity	DARE MT PLEASANT/COLLEGE LCP 980	140	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	309
49	LVD Lines Capacity	DARE Rodney-Rodney LCP 923	32	1	Project	Overloaded Equipment Upgrades	MECOSTA	Overload Failure Reduction; Customers	57
50	LVD Lines Capacity	DARE RYNO_MORENCI LCP 358	66	1	Project	Overloaded Equipment Upgrades	MIO	Overload Failure Reduction; Customers	456
51	LVD Lines Capacity	DARE Trufant_Gowen LCP 570 and 876	42	1	Project	Overloaded Equipment Upgrades	SPENCER TOWNSHIP	Overload Failure Reduction; Customers	299
52	LVD Lines Capacity	DARE WARNER-BURCHETT 312 ISOLATOR	140	1	Project	Overloaded Equipment Upgrades	PRAIRIEVILLE TOWNSHIP	Overload Failure Reduction; Customers	144
53	LVD Lines Capacity	DARE19 SURREY SURREY LCP 708	121	1	Project	Overloaded Equipment Upgrades	FARWELL	Overload Failure Reduction; Customers	251
54	LVD Lines Capacity	DARE21 CEDAR LAKE_KINGS CORNER 702	30	1	Project	Overloaded Equipment Upgrades	OSCODA	Overload Failure Reduction; Customers	98
55	LVD Lines Capacity	DARE BIRCH RUN/SAGINAW ROAD LCP 515	482	1	Project	Overloaded Equipment Upgrades	BIRCH RUN TOWNSHIP	Overload Failure Reduction; Customers	274
56	LVD Lines Capacity	DARE BRIDGEPORT/DIXIE LCP 664	90	1	Project	Overloaded Equipment Upgrades	BRIDGEPORT TOWNSHIP	Overload Failure Reduction; Customers	59
57	LVD Lines Capacity	DARE Camelot Lake_Coleman LCP 513 Part 2	581	1	Project	Overloaded Equipment Upgrades	GREENDALE TOWNSHIP	Overload Failure Reduction; Customers	597
58	LVD Lines Capacity	DARE CANNONSBURG/WEST CANNON LCP-840	470	1	Project	Overloaded Equipment Upgrades	BELMONT	Overload Failure Reduction; Customers	114
59	LVD Lines Capacity	DARE CASINO_LEATON LCP 625	20	1	Project	Overloaded Equipment Upgrades	CHIPPEWA TOWNSHIP	Overload Failure Reduction; Customers	69
60	LVD Lines Capacity	DARE CONVIS CONVIS LCP 369	9	1	Project	Overloaded Equipment Upgrades	CONVIS TOWNSHIP	Overload Failure Reduction; Customers	40
61		**LVD Lines Capacity Subtotal**	**10,779**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 26 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE EASTLAWN_FLAJOLE LCP 530	4	1	Project	Overloaded Equipment Upgrades	MIDLAND	Overload Failure Reduction; Customers	1337
2	LVD Lines Capacity	DARE FREELAND_FREELAND LCP 661	229	1	Project	Overloaded Equipment Upgrades	FREELAND	Overload Failure Reduction; Customers	122
3	LVD Lines Capacity	DARE HENDERSHOT_CENTENNIAL LCP 585	23	1	Project	Overloaded Equipment Upgrades	ADRIAN TOWNSHIP	Overload Failure Reduction; Customers	431
4	LVD Lines Capacity	DARE ITHACA_FAIR GROUNDS LCP 463	47	1	Project	Overloaded Equipment Upgrades	ARCADA TOWNSHIP	Overload Failure Reduction; Customers	45
5	LVD Lines Capacity	DARE PLAINWELL_COMMERCIAL LCP 551	13	1	Project	Overloaded Equipment Upgrades	GUN PLAIN TOWNSHIP	Overload Failure Reduction; Customers	32
6	LVD Lines Capacity	DARE18 COGGINS_ALMEDA LCP 780	130	1	Project	Overloaded Equipment Upgrades	PINCONNING	Overload Failure Reduction; Customers	103
7	LVD Lines Capacity	DARE18 COWAN LAKE/RAMSDELL OVERLOADED FU	33	1	Project	Overloaded Equipment Upgrades	ROCKFORD	Overload Failure Reduction; Customers	131
8	LVD Lines Capacity	DARE18 DEWEY SEATING (ENGY DIST ALT FEED	419	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	3615
9	LVD Lines Capacity	DARE18 HARRISON HARRISON LCP 381	16	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	292
10	LVD Lines Capacity	MARKEY_CARRICK LCP 731	62	1	Project	Overloaded Equipment Upgrades	GERRISH TOWNSHIP	Overload Failure Reduction; Customers	245
11	LVD Lines Capacity	MCBAIN_VOGEL CENTER LCP 064	42	1	Project	Overloaded Equipment Upgrades	CLAM UNION TOWNSHIP	Overload Failure Reduction; Customers	317
12	LVD Lines Capacity	MCBAIN_LAKE CITY LCP 0761	25	1	Project	Overloaded Equipment Upgrades	CLAM UNION TOWNSHIP	Overload Failure Reduction; Customers	145
13	LVD Lines Capacity	DARE ST CHARLES/FERGUS LCP 387	86	1	Project	Overloaded Equipment Upgrades	ST CHARLES TOWNSHIP	Overload Failure Reduction; Customers	27
14	LVD Lines Capacity	DARE17 CHESANING/CHESANING LCP 360	74	1	Project	Overloaded Equipment Upgrades	CHESANING TOWNSHIP	Overload Failure Reduction; Customers	133
15	LVD Lines Capacity	DARE17 FRANKENMUTH/GERA LCP 942	86	1	Project	Overloaded Equipment Upgrades	BLUMFIELD TOWNSHIP	Overload Failure Reduction; Customers	30
16	LVD Lines Capacity	DARE17 GROVER/TRIANGLE LCP 361	16	1	Project	Overloaded Equipment Upgrades	EMERSON TOWNSHIP	Overload Failure Reduction; Customers	308
17	LVD Lines Capacity	DARE17 ISABELLA/PICKARD LCP 789	7	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	209
18	LVD Lines Capacity	DARE17 KAWKAWLIN/LAGOON BEACH LCP 422	105	1	Project	Overloaded Equipment Upgrades	KAWKAWLIN	Overload Failure Reduction; Customers	927
19	LVD Lines Capacity	DARE17 MORLEY/HOLLAND LCP 723	49	1	Project	Overloaded Equipment Upgrades	BUENA VISTA TOWNSHIP	Overload Failure Reduction; Customers	122
20	LVD Lines Capacity	MONA LAKE_AIRPORT LCP 564	12	1	Project	Overloaded Equipment Upgrades	CITY OF NORTON SHORES	Overload Failure Reduction; Customers	1171
21	LVD Lines Capacity	MONTEREY_30TH STREET LCP 818	60	1	Project	Overloaded Equipment Upgrades	SALEM TOWNSHIP	Overload Failure Reduction; Customers	130
22	LVD Lines Capacity	DARE17 PINE RIVER/RURAL LCP 219	130	1	Project	Overloaded Equipment Upgrades	ALMA	Overload Failure Reduction; Customers	93
23	LVD Lines Capacity	DARE17 STARKS/HOMER LCP 654	182	1	Project	Overloaded Equipment Upgrades	HOMER TOWNSHIP	Overload Failure Reduction; Customers	342
24	LVD Lines Capacity	DARE17 SWAN CREEK_MINING	771	1	Project	Overloaded Equipment Upgrades	CHESHIRE TOWNSHIP	Overload Failure Reduction; Customers	180
25	LVD Lines Capacity	DARE17 ULMER/BURT ROAD LCP 429	49	1	Project	Overloaded Equipment Upgrades	BIRCH RUN TOWNSHIP	Overload Failure Reduction; Customers	59
26	LVD Lines Capacity	DARE18 BULLOCK/STEWART LCP 421	3	1	Project	Overloaded Equipment Upgrades	HOMER TOWNSHIP	Overload Failure Reduction; Customers	122
27	LVD Lines Capacity	NEWBURG_VERNON LCP 464	30	1	Project	Overloaded Equipment Upgrades	VERNON TOWNSHIP	Overload Failure Reduction; Customers	31
28	LVD Lines Capacity	OBERLIN_BENMARK LCP 589	40	1	Project	Overloaded Equipment Upgrades	BUTMAN TOWNSHIP	Overload Failure Reduction; Customers	119
29	LVD Lines Capacity	DARE18 CARLETON ROAD_BECK ROAD	2	1	Project	Overloaded Equipment Upgrades	HILLSDALE TOWNSHIP	Overload Failure Reduction; Customers	46
30	LVD Lines Capacity	DARE18 CHAPIN/MARION LCP 141	531	1	Project	Overloaded Equipment Upgrades	MARION TOWNSHIP	Overload Failure Reduction; Customers	620
31	LVD Lines Capacity	OBERLIN_BENMARK LCP 845	60	1	Project	Overloaded Equipment Upgrades	BUTMAN TOWNSHIP	Overload Failure Reduction; Customers	128
32	LVD Lines Capacity	DARE18 JONESVILLE_JONESVILLE	2	1	Project	Overloaded Equipment Upgrades	HILLSDALE TOWNSHIP	Overload Failure Reduction; Customers	115
33	LVD Lines Capacity	DARE18 KINDERHOOK_LAKE DRIVE	109	1	Project	Overloaded Equipment Upgrades	OVID TOWNSHIP	Overload Failure Reduction; Customers	565
34	LVD Lines Capacity	DARE18 MORLEY/HOLLAND LCP 712	49	1	Project	Overloaded Equipment Upgrades	BUENA VISTA TOWNSHIP	Overload Failure Reduction; Customers	20
35	LVD Lines Capacity	DARE18 NAPOLEON/NORVELL-980-AUSTIN W/O B	535	1	Project	Overloaded Equipment Upgrades	NORVELL TOWNSHIP	Overload Failure Reduction; Customers	42
36	LVD Lines Capacity	OTISVILLE_IRISH ROAD LCP 072	20	1	Project	Overloaded Equipment Upgrades	FOREST TOWNSHIP	Overload Failure Reduction; Customers	33
37	LVD Lines Capacity	DARE18 SURREY SURREY LCP 680	202	1	Project	Overloaded Equipment Upgrades	FARWELL	Overload Failure Reduction; Customers	162
38	LVD Lines Capacity	DARE18 Watkins Christy 491	58	1	Project	Overloaded Equipment Upgrades	BATTLE CREEK TOWNSHIP	Overload Failure Reduction; Customers	80
39	LVD Lines Capacity	DARE18 WEIDMAN WEIDMAN LCP 640	242	1	Project	Overloaded Equipment Upgrades	ROSEBUSH	Overload Failure Reduction; Customers	47
40	LVD Lines Capacity	DARE19 BLUE STAR/PIER COVE LCP 619	522	1	Project	Overloaded Equipment Upgrades	GANGES TOWNSHIP	Overload Failure Reduction; Customers	131
41	LVD Lines Capacity	DARE19 Fine Lake - Bristol	216	1	Project	Overloaded Equipment Upgrades	ASSYRIA TOWNSHIP	Overload Failure Reduction; Customers	261
42	LVD Lines Capacity	DARE19 HARRISON STOCKWELL LCP 074	282	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	222
43	LVD Lines Capacity	DARE19 Olivet Ainger LCP 521	215	1	Project	Overloaded Equipment Upgrades	WALTON TOWNSHIP	Overload Failure Reduction; Customers	268
44	LVD Lines Capacity	PETTIS ROAD_HONEY CREEK LCP 980	198	1	Project	Overloaded Equipment Upgrades	ADA TOWNSHIP	Overload Failure Reduction; Customers	31
45	LVD Lines Capacity	DARE21 Cedar Springs-Edgerton LCP 555	413	1	Project	Overloaded Equipment Upgrades	CEDAR SPRINGS	Overload Failure Reduction; Customers	121
46	LVD Lines Capacity	DARE21 Levely_Albright LCP 250	153	1	Project	Overloaded Equipment Upgrades	TOBACCO TOWNSHIP	Overload Failure Reduction; Customers	253
47	LVD Lines Capacity	DARE PORT CALCITE_WOODWARD LCP 0487 REG	221	1	Project	Overloaded Equipment Upgrades	CITY OF ROGERS CITY	Overload Failure Reduction; Customers	413
48	LVD Lines Capacity	POTTERVILLE_M-78 LCP 565	5	1	Project	Overloaded Equipment Upgrades	WINDSOR TOWNSHIP	Overload Failure Reduction; Customers	81
49	LVD Lines Capacity	DARE21 Levely_Allbright LCP 239	7	1	Project	Overloaded Equipment Upgrades	TOBACCO TOWNSHIP	Overload Failure Reduction; Customers	54
50	LVD Lines Capacity	DARE21 Levely_Allbright LCP 665	437	1	Project	Overloaded Equipment Upgrades	BILLINGS TOWNSHIP	Overload Failure Reduction; Customers	678
51	LVD Lines Capacity	DARE21 PARAMOUNT/BIRD	120	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	728
52	LVD Lines Capacity	DARE21 PORTAGE SHAVER RD OAKLAND	78	1	Project	Overloaded Equipment Upgrades	PORTAGE	Overload Failure Reduction; Customers	282
53	LVD Lines Capacity	RANGER LAKE_LUPTON LCP 087	450	1	Project	Overloaded Equipment Upgrades	PLAINFIELD TOWNSHIP	Overload Failure Reduction; Customers	254
54	LVD Lines Capacity	RANGER LAKE_GOODAR LCP 185	850	1	Project	Overloaded Equipment Upgrades	PLAINFIELD TOWNSHIP	Overload Failure Reduction; Customers	258
55	LVD Lines Capacity	RANGER LAKE_LUPTON LCP 428	24	1	Project	Overloaded Equipment Upgrades	HILL TOWNSHIP	Overload Failure Reduction; Customers	529
56	LVD Lines Capacity	RIVERDALE_SUMNER LCP 019	24	1	Project	Overloaded Equipment Upgrades	SUMNER TOWNSHIP	Overload Failure Reduction; Customers	18
57	LVD Lines Capacity	DARE21-CARLETON RD-BECK RD-UG Cable	5	1	Project	Overloaded Equipment Upgrades	HILLSDALE TOWNSHIP	Overload Failure Reduction; Customers	1
58	LVD Lines Capacity	DARE21-DOBSON RD-HALF MOON-LCP 375	95	1	Project	Overloaded Equipment Upgrades	SCIPIO TOWNSHIP	Overload Failure Reduction; Customers	50
59	LVD Lines Capacity	DARE Greenwood_Rau Rd LCP 837	573	1	Project	Overloaded Equipment Upgrades	WEST BRANCH	Overload Failure Reduction; Customers	147
60		**LVD Lines Capacity Subtotal**	**9,439**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 27 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	ROGUE RIVER_ROGUE RIVER LCP 472	39	1	Project	Overloaded Equipment Upgrades	CITY OF ROCKFORD	Overload Failure Reduction; Customers	93
2	LVD Lines Capacity	ROSE CITY_ISLAND LAKE LCP 108	62	1	Project	Overloaded Equipment Upgrades	FOSTER TOWNSHIP	Overload Failure Reduction; Customers	472
3	LVD Lines Capacity	ROSEBUSH_STEVENSON LAKE LCP 881	90	1	Project	Overloaded Equipment Upgrades	ISABELLA TOWNSHIP	Overload Failure Reduction; Customers	148
4	LVD Lines Capacity	RUSSELLVILLE_VICTORIA LCP 268	240	1	Project	Overloaded Equipment Upgrades	RICHFIELD TOWNSHIP	Overload Failure Reduction; Customers	220
5	LVD Lines Capacity	RUSSELLVILLE_VICTORIA LCP 830	240	1	Project	Overloaded Equipment Upgrades	RICHFIELD TOWNSHIP	Overload Failure Reduction; Customers	408
6	LVD Lines Capacity	SARANAC_KEENE LCP 868	240	1	Project	Overloaded Equipment Upgrades	KEENE TOWNSHIP	Overload Failure Reduction; Customers	81
7	LVD Lines Capacity	SAUGATUCK_SILVER LAKE LCP 340	90	1	Project	Overloaded Equipment Upgrades	SAUGATUCK TOWNSHIP	Overload Failure Reduction; Customers	329
8	LVD Lines Capacity	SHERIDAN_FENWICK LCP 7007	85	1	Project	Overloaded Equipment Upgrades	BUSHNELL TOWNSHIP	Overload Failure Reduction; Customers	3
9	LVD Lines Capacity	SINCLAIR_SPECTRUM LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	13
10	LVD Lines Capacity	SKYLARK_ROCKING CHAIR LCP 979	240	1	Project	Overloaded Equipment Upgrades	GRAND BLANC TOWNSHIP	Overload Failure Reduction; Customers	310
11	LVD Lines Capacity	SKYLARK_SUN VALLEY LCP	700	1	Project	Overloaded Equipment Upgrades	GRAND BLANC TOWNSHIP	Overload Failure Reduction; Customers	1376
12	LVD Lines Capacity	SMALLWOOD DAM_DISTRIBUTION LCP 607	90	1	Project	Overloaded Equipment Upgrades	HAY TOWNSHIP	Overload Failure Reduction; Customers	345
13	LVD Lines Capacity	SPRUCE ROAD_BLACK RIVER LCP 187	85	1	Project	Overloaded Equipment Upgrades	HAYNES TOWNSHIP	Overload Failure Reduction; Customers	87
14	LVD Lines Capacity	ST HELEN_ARTESIA LCP 090	30	1	Project	Overloaded Equipment Upgrades	RICHFIELD TOWNSHIP	Overload Failure Reduction; Customers	851
15	LVD Lines Capacity	STANDALE_STANDALE LCP 111	85	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	363
16	LVD Lines Capacity	STANDALE_STANDALE LCP 267	85	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	324
17	LVD Lines Capacity	STANDALE_STANDALE LCP 356	85	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	269
18	LVD Lines Capacity	STANDISH_STERLING LCP	700	1	Project	Overloaded Equipment Upgrades	CITY OF STANDISH	Overload Failure Reduction; Customers	2050
19	LVD Lines Capacity	STANDISH_STERLING LCP	90	1	Project	Overloaded Equipment Upgrades	CITY OF STANDISH	Overload Failure Reduction; Customers	2050
20	LVD Lines Capacity	STANDISH_STERLING LCP 239	240	1	Project	Overloaded Equipment Upgrades	CITY OF STANDISH	Overload Failure Reduction; Customers	25
21	LVD Lines Capacity	STARKS_HOMER LCP 429	90	1	Project	Overloaded Equipment Upgrades	HOMER TOWNSHIP	Overload Failure Reduction; Customers	238
22	LVD Lines Capacity	STARKS_LEE LCP 769	90	1	Project	Overloaded Equipment Upgrades	HOMER TOWNSHIP	Overload Failure Reduction; Customers	452
23	LVD Lines Capacity	STEVENS_HYNES LCP	750	1	Project	Overloaded Equipment Upgrades	CITY OF GRAND RAPIDS	Overload Failure Reduction; Customers	1
24	LVD Lines Capacity	SURREY_MAIN STREET LCP 402	130	1	Project	Overloaded Equipment Upgrades	VERNON TOWNSHIP	Overload Failure Reduction; Customers	118
25	LVD Lines Capacity	TAMARACK_AMBLE LCP 099	85	1	Project	Overloaded Equipment Upgrades	CATO TOWNSHIP	Overload Failure Reduction; Customers	83
26	LVD Lines Capacity	TAMARACK_AMBLE LCP 101	85	1	Project	Overloaded Equipment Upgrades	CATO TOWNSHIP	Overload Failure Reduction; Customers	41
27	LVD Lines Capacity	TAWAS_TAWAS LCP 205	210	1	Project	Overloaded Equipment Upgrades	TAWAS TOWNSHIP	Overload Failure Reduction; Customers	208
28	LVD Lines Capacity	TAWAS_TAWAS LCP 263	90	1	Project	Overloaded Equipment Upgrades	CITY OF TAWAS CITY	Overload Failure Reduction; Customers	263
29	LVD Lines Capacity	TEFT ROAD_LAKEFIELD LCP 171	90	1	Project	Overloaded Equipment Upgrades	SWAN CREEK TOWNSHIP	Overload Failure Reduction; Customers	490
30	LVD Lines Capacity	THORNTON_NIELSON RD LCP 7028	85	1	Project	Overloaded Equipment Upgrades	JEROME TOWNSHIP	Overload Failure Reduction; Customers	16
31	LVD Lines Capacity	THORNTON_WEST RIVER RD LCP 201	6	1	Project	Overloaded Equipment Upgrades	JEROME TOWNSHIP	Overload Failure Reduction; Customers	297
32	LVD Lines Capacity	THORNTON_WEST RIVER RD LCP 725	192	1	Project	Overloaded Equipment Upgrades	JEROME TOWNSHIP	Overload Failure Reduction; Customers	297
33	LVD Lines Capacity	TRUFANT_GOWEN LCP 564	210	1	Project	Overloaded Equipment Upgrades	SPENCER TOWNSHIP	Overload Failure Reduction; Customers	165
34	LVD Lines Capacity	TRUFANT_HUNTER LAKE LCP 385	85	1	Project	Overloaded Equipment Upgrades	PINE TOWNSHIP	Overload Failure Reduction; Customers	76
35	LVD Lines Capacity	TRUFANT_HUNTER LAKE LCP 869	85	1	Project	Overloaded Equipment Upgrades	PINE TOWNSHIP	Overload Failure Reduction; Customers	239
36	LVD Lines Capacity	TUCKER_OAK HILL LCP	750	1	Project	Overloaded Equipment Upgrades	GROVELAND TOWNSHIP	Overload Failure Reduction; Customers	186
37	LVD Lines Capacity	TUCKER_OAK HILL LCP 203	85	1	Project	Overloaded Equipment Upgrades	GROVELAND TOWNSHIP	Overload Failure Reduction; Customers	187
38	LVD Lines Capacity	TUCKER_OAK HILL LCP 330	240	1	Project	Overloaded Equipment Upgrades	SPRINGFIELD TOWNSHIP	Overload Failure Reduction; Customers	723
39	LVD Lines Capacity	WAMPLERS_STAGECOACH LCP 132	210	1	Project	Overloaded Equipment Upgrades	CAMBRIDGE TOWNSHIP	Overload Failure Reduction; Customers	466
40	LVD Lines Capacity	WAMPLERS_STAGECOACH LCP 173	90	1	Project	Overloaded Equipment Upgrades	CAMBRIDGE TOWNSHIP	Overload Failure Reduction; Customers	462
41	LVD Lines Capacity	DARE18 PEACH RIDGE/KENOWA CONV PT5	486	1	Project	Sub Capacity-associated Line Work	GRAND RAPIDS	Overload Failure Reduction; Customers	133
42	LVD Lines Capacity	DARE18 PEACH RIDGE/BALLARD Conv PT3	968	1	Project	Sub Capacity-associated Line Work	GRAND RAPIDS	Overload Failure Reduction; Customers	133
43	LVD Lines Capacity	DARE22 Tamarack-Amble Conv phase 2-Part1	354	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	474
44		**LVD Lines Capacity Subtotal**	**9,732**						
45		**LVD Lines Capacity Total**	**54,911**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2027
($4,070)

Case No.: U-21870
Exhibit No.: A-167 (JMP-2)
Page: 28 of 28
Witness: JMPartlan
Date: June 2025

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	CVR	CVR_ALPINE_ALPINE	38	1	Circuit	Conservation Voltage Reduction	ALPINE TWP	kW Energy Savings	163
2		CVR_APPLETON_PERRY	79	1	Circuit	Conservation Voltage Reduction	BIG RAPIDS TWP	kW Energy Savings	216
3		CVR_APPLETON_WALDRON WAY	13	1	Circuit	Conservation Voltage Reduction	BIG RAPIDS TWP	kW Energy Savings	140
4		CVR_ASHMAN CIRCLE_HIGH SCHOOL	46	1	Circuit	Conservation Voltage Reduction	MIDLAND TWP	kW Energy Savings	123
5		CVR_BABCOCK_FRANCISCO	20	1	Circuit	Conservation Voltage Reduction	SHERWOOD TWP	kW Energy Savings	27
6		CVR_BEALS ROAD_CLYDE PARK	268	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	250
7		CVR_BEALS ROAD_EXPRESSWAY	30	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	111
8		CVR_BEECHER_DISPOSAL	20	1	Circuit	Conservation Voltage Reduction	MADISON TWP	kW Energy Savings	91
9		CVR_BELKNAP_BELKNAP	20	1	Circuit	Conservation Voltage Reduction	OVERISEL TWP	kW Energy Savings	21
10		CVR_BENNETT_KNOB HILL	56	1	Circuit	Conservation Voltage Reduction	MERIDIAN TWP	kW Energy Savings	143
11		CVR_BENSTON_DURHAM	27	1	Circuit	Conservation Voltage Reduction	WHITEHALL TWP	kW Energy Savings	103
12		CVR_BENSTON_LEWIS	26	1	Circuit	Conservation Voltage Reduction	WHITEHALL TWP	kW Energy Savings	134
13		CVR_BLUEGRASS_BLUEGRASS	38	1	Circuit	Conservation Voltage Reduction	CHIPPEWA TWP	kW Energy Savings	92
14		CVR_BOSTON SQUARE_NELAND	67	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	144
15		CVR_BOYNE CITY_VETERANS	36	1	Circuit	Conservation Voltage Reduction	EVANGELINE TWP	kW Energy Savings	90
16		CVR_BRIDGEPORT_BRIDGEPORT	69	1	Circuit	Conservation Voltage Reduction	BRIDGEPORT TWP	kW Energy Savings	151
17		CVR_CHESANING_OAKLEY	19	1	Circuit	Conservation Voltage Reduction	CHESANING TWP	kW Energy Savings	79
18		CVR_CLIO_PINE RUN	51	1	Circuit	Conservation Voltage Reduction	VIENNA TWP	kW Energy Savings	113
19		CVR_CORUNNA_STATE ROAD	27	1	Circuit	Conservation Voltage Reduction	CALEDONIA TWP	kW Energy Savings	98
20		CVR_CORUNNA_COURTHOUSE	39	1	Circuit	Conservation Voltage Reduction	CALEDONIA TWP	kW Energy Savings	160
21		CVR_COURT_WOODLAWN	37	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	120
22		CVR_DALE ROAD_M-18	20	1	Circuit	Conservation Voltage Reduction	BEAVERTON TWP	kW Energy Savings	139
23		CVR_DALE ROAD_BEAR CREEK	20	1	Circuit	Conservation Voltage Reduction	BEAVERTON TWP	kW Energy Savings	28
24		CVR_DEWEY_BRIDGEWATER	14	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	93
25		CVR_DEWEY_CONVENTION CENTER	15	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	44
26		CVR_DIMONDALE_M-99	53	1	Circuit	Conservation Voltage Reduction	WINDSOR TWP	kW Energy Savings	136
27		CVR_ELM STREET_MAIN	29	1	Circuit	Conservation Voltage Reduction	BATTLE CREEK	kW Energy Savings	82
28		CVR_ERIE_COUSINO ROAD	20	1	Circuit	Conservation Voltage Reduction	ERIE TWP	kW Energy Savings	70
29		CVR_FERGUSON_BROWNS LAKE	63	1	Circuit	Conservation Voltage Reduction	SUMMIT TWP	kW Energy Savings	146
30		CVR_FERGUSON_KIBBY ROAD	47	1	Circuit	Conservation Voltage Reduction	SUMMIT TWP	kW Energy Savings	117
31		CVR_FIELD ROAD_FARRAND	31	1	Circuit	Conservation Voltage Reduction	VIENNA TWP	kW Energy Savings	100
32		CVR_FISH LAKE_SEVEN LAKES	28	1	Circuit	Conservation Voltage Reduction	HOLLY TWP	kW Energy Savings	99
33		CVR_GOLDEN_SCHUETTE	20	1	Circuit	Conservation Voltage Reduction	MIDLAND TWP	kW Energy Savings	44
34		CVR_GUN LAKE_ENGLAND	121	1	Circuit	Conservation Voltage Reduction	ORANGEVILLE TWP	kW Energy Savings	188
35		CVR_HANSEN_HANSEN	63	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	145
36		CVR_HARPER ROAD_AURELIUS	109	1	Circuit	Conservation Voltage Reduction	DELHI TWP	kW Energy Savings	167
37		CVR_HARVEY STREET_CORRECTION	53	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	327
38		CVR_HARVEY STREET_HEIGHTS	71	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	121
39		CVR_HASKELITE_RICHMOND	44	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	137
40		CVR_HUBBARD LAKE_HUBBARD LAKE	15	1	Circuit	Conservation Voltage Reduction	WEST HAWES TWP	kW Energy Savings	19
41		CVR_ITHACA_COURT HOUSE	50	1	Circuit	Conservation Voltage Reduction	NEWARK TWP	kW Energy Savings	156
42		CVR_JAMESTOWN_CORPORATE	19	1	Circuit	Conservation Voltage Reduction	JAMESTOWN TWP	kW Energy Savings	257
43		CVR_JUDD ROAD_AINSWORTH	57	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	126
44		CVR_KAWKAWLIN_LAGOON BEACH	39	1	Circuit	Conservation Voltage Reduction	KAWKAWLIN TWP	kW Energy Savings	99
45		CVR_KELLOGGSVILLE_HOME ACRES	104	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	176
46		CVR_KROMDYKE_ROMONA	20	1	Circuit	Conservation Voltage Reduction	PORTAGE	kW Energy Savings	45
47		CVR_LABARGE_ALASKA	19	1	Circuit	Conservation Voltage Reduction	CALEDONIA TWP	kW Energy Savings	73
48		CVR_LARKIN_EASTMAN	66	1	Circuit	Conservation Voltage Reduction	MIDLAND TWP	kW Energy Savings	136
49		CVR_LARKIN_N MIDLAND	20	1	Circuit	Conservation Voltage Reduction	MIDLAND TWP	kW Energy Savings	56
50		CVR_LEE STREET_LEE	62	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	300
51		CVR_LEE STREET_KIRTLAND	206	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	252
52		CVR_LEONARD_TAYLOR	113	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	189
53		CVR_MAPLE GROVE_SUMMIT AVENUE	79	1	Circuit	Conservation Voltage Reduction	FRUITPORT TWP	kW Energy Savings	115
54		CVR_MCMILLAN_BEATTIE	20	1	Circuit	Conservation Voltage Reduction	DALTON TWP	kW Energy Savings	52
55		CVR_MENDON_M-60	61	1	Circuit	Conservation Voltage Reduction	NOTTAWA TWP	kW Energy Savings	237
56		CVR_MERIDIAN_LAKE LANSING	27	1	Circuit	Conservation Voltage Reduction	MERIDIAN TWP	kW Energy Savings	90
57		CVR_MIDLAND_NORTHWOOD	20	1	Circuit	Conservation Voltage Reduction	MIDLAND TWP	kW Energy Savings	92
58		CVR_MISSION_THREE LEAVES	24	1	Circuit	Conservation Voltage Reduction	UNION TWP	kW Energy Savings	108
59		CVR_MONA LAKE_GRAND HAVEN	21	1	Circuit	Conservation Voltage Reduction	FRUITPORT TWP	kW Energy Savings	155
60		CVR_NEFF ROAD_DODGE ROAD	90	1	Circuit	Conservation Voltage Reduction	THETFORD TWP	kW Energy Savings	163
61		CVR_NEW HAVEN_HENDERSON	20	1	Circuit	Conservation Voltage Reduction	NEW HAVEN TWP	kW Energy Savings	44
62		CVR_OWOSSO_BUSINESS	18	1	Circuit	Conservation Voltage Reduction	CALEDONIA TWP	kW Energy Savings	77
63		CVR_PENNFIELD_PENNFIELD	20	1	Circuit	Conservation Voltage Reduction	PENNFIELD TWP	kW Energy Savings	65
64		CVR_PORTER_PARTS	75	1	Circuit	Conservation Voltage Reduction	GRAND BLANC TWP	kW Energy Savings	110
65		CVR_RAMONA_ROBINSON	53	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	110
66		CVR_RAMONA_REEDS LAKE	46	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	121
67		CVR_RIVERTOWN_SATTLER	86	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	175
68		CVR_RIVERTOWN_POTOMAC	102	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	220
69		CVR_RUSSELLVILLE_RICHFIELD	35	1	Circuit	Conservation Voltage Reduction	RICHFIELD TWP	kW Energy Savings	97
70		CVR_RUSSELLVILLE_VASSAR ROAD	25	1	Circuit	Conservation Voltage Reduction	RICHFIELD TWP	kW Energy Savings	93
71		CVR_SAVIDGE_KELLY STREET	26	1	Circuit	Conservation Voltage Reduction	SPRING LAKE TWP	kW Energy Savings	87
72		CVR_SHATTUCK_COUNTY FARM	73	1	Circuit	Conservation Voltage Reduction	SAGINAW	kW Energy Savings	160
73		CVR_SHIELDS_SWAN CREEK	19	1	Circuit	Conservation Voltage Reduction	SWAN CREEK TWP	kW Energy Savings	68
74		CVR_SLOAN_LONGFELLOW	65	1	Circuit	Conservation Voltage Reduction	FLINT	kW Energy Savings	116
75		CVR_SPRING ARBOR_CHAPEL	38	1	Circuit	Conservation Voltage Reduction	SPRING ARBOR TWP	kW Energy Savings	133
76		CVR_SPRING ARBOR_ARBOR HILLS	52	1	Circuit	Conservation Voltage Reduction	SPRING ARBOR TWP	kW Energy Savings	119
77		CVR_ST HELEN_KENO	20	1	Circuit	Conservation Voltage Reduction	AU SABLE TWP	kW Energy Savings	14
78		CVR_STEEL DRIVE_OWEN ROAD	41	1	Circuit	Conservation Voltage Reduction	FENTON TWP	kW Energy Savings	150
79		CVR_STEEL DRIVE_VISTA	57	1	Circuit	Conservation Voltage Reduction	FENTON TWP	kW Energy Savings	142
80		CVR_TERRACE_MALL	50	1	Circuit	Conservation Voltage Reduction	MUSKEGON	kW Energy Savings	135
81		CVR_TITUS LAKE_TENTH STREET	36	1	Circuit	Conservation Voltage Reduction	WAYLAND TWP	kW Energy Savings	120
82		CVR_UNIVERSITY_HARRISON	17	1	Circuit	Conservation Voltage Reduction	LANSING TWP	kW Energy Savings	103
83		CVR_WASHINGTON_CONRAD	32	1	Circuit	Conservation Voltage Reduction	PERE MARQUETTE TWP	kW Energy Savings	222
84		CVR_WATKINS_CHRISTY	35	1	Circuit	Conservation Voltage Reduction	BATTLE CREEK TWP	kW Energy Savings	139
85		CVR_WEALTHY STREET_BUTTERWORTH	50	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	135
		CVR Subtotal	**4,070**						



Consumers Energy

Conservation Voltage Reduction Measurement and Verification Independent Assessment

May 2021

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21525 Ridgetop Circle, Suite 200
Sterling, Virginia, 20166
USA

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EXECUTIVE SUMMARY

Conservation Voltage Reduction (CVR) is the practice of reducing service delivery voltage to the lower portion of the acceptable industry range as specified in ANSI Standard C84.1 to reduce energy consumption for waste energy reduction purposes and/or reduce peak electrical demand. Consumers Energy of Jackson, Michigan has conducted a CVR Demonstration Project that included implementing CVR on fifty of its electric distribution feeders that are located throughout the Consumers Energy service territory and has been operating in CVR reduced-voltage mode on alternating days since 2019.

To determine the waste energy and peak demand reduction that can be attributed to voltage reduction, Consumers Energy has conducted a Measurement and Verification (M&V) analysis of the electrical measurement data collected for each of the fifty feeders during the period of CVR alternating-day (aka, "day-on/day-off") operation. This analysis separates the electrical impacts of voltage reduction from other factors that affect the energy consumption and peak electrical demand, such as naturally varying custom behavior and ambient weather conditions, as well as variations in energy consumption for different hours of the day, days of the week, seasons, and other temporal variations.

In January 2021, Consumers Energy hired ESTA International, Ltd. (ESTA), an independent consulting firm specializing in electric utility automation and energy analysis to review and critique the Consumers Energy CVR project and associated M&V analysis performed by Consumers Energy. This report summarizes the results of this assessment.

M&V ASSESSMENT FACTORS

ESTA's assessment of the Consumers Energy CVR M&V approach included the following items:

- Process for Selecting Feeders. Consumers Energy will use the results of the CVR demonstration project to determine whether CVR implementation on additional feeders is justified. Therefore, the 50 feeders selected for the CVR demonstration should have characteristics (customer mix, regional distribution, etc.) that are representative of other Consumers Energy feeders on which CVR may be implemented in the future. Consumers Energy used a two-step process for selecting feeders for the CVR demonstration:
    - During Step 1, Consumers Energy identified 1,700 feeders that are viable candidates for implementing CVR based on factors such as availability of remote-controlled devices and telecommunication facilities. These feeders are labeled the "CVR Proposed" set.
    - During Step 2, Consumers Energy selected 50 feeders from the CVR Proposed set on which to implement CVR for demonstration purposes. In selecting these 50 feeders, preference was given to feeders with characteristics that best match the CVR proposed set. Preference was given to feeders that have a similar mix of residential, commercial and industrial customers.

  The feeder selection process used by Consumers Energy is far more detailed and superior to the selection process used by other utility companies. In ESTA's opinion, the selected CVR feeders are representative of the CVR Proposed set of feeders and, therefore, it is acceptable to assume that similar results will be obtained as CVR is added by Consumers Energy to additional feeders.

- CVR System. The CVR system deployed by Consumers Energy is like most CVR systems that have been deployed in the past 5 to 10 years by other electric utilities. This system applies fixed "rules" that have been predetermined by Engineering to real-time measurements obtained by the Consumers Energy SCADA system to determine what control actions (if any) are needed for switched capacitor banks and voltage

regulators. The CVR system automatically switched between CVR-On mode (reduced voltage) to CVR Off mode (normal voltage) on alternating days. In ESTA's opinion, the rules-based approach is a cost-effective approach that is well suited to the project's "proof of concept" objectives. One shortcoming of this approach is that the system must be disabled for a given feeder if that feeder is reconfigured. This is not a major problem because such reconfiguration is infrequent. However, ESTA recommends a "model-driven" approach to CVR that automatically adapts when feeders are reconfigured. This approach can be implemented on the new Consumers Energy ADMS.

- Controlled Devices: The Consumers Energy CVR system controls switched capacitor banks and voltage regulators as needed to accomplish the CVR objectives. This is consistent with industry practice. Consumers Energy has a significant advantage over many other utility companies because voltage regulation is done on an individual-feeder basis. This enables Consumers Energy to reduce voltage on some feeders even if other feeders fed by the same substation are "voltage limited". In the future, control of other devices such as Distributed Energy Resources (DERs) with "smart inverters", may be required by Consumers Energy. The previously mentioned model-drive solution will be able to handle the addition of such devices.

- Data Collected During the Demonstrations: ESTA reviewed the list of electrical measurements collected during the CVR demonstrations to determine if the measurements taken are sufficient for effective operation of the CVR algorithms and determining the CVR factors. ESTA concludes that the collected data is consistent with the data collected by other utilities and is sufficient for computing the CVR factors for the CVR demonstration feeders. Some "data scrubbing" was performed by Consumers Energy to eliminate data anomalies. However, ESTA notes that the amount of data scrubbing needed by Consumers Energy for its data was much less than the data scrubbing needed by other utilities, indicating that the Consumers Energy data quality, in general, is very good.

- Method of Computing CVR factors for Waste Energy Reduction and Peak Demand Reduction. ESTA reviewed the method used by Consumers Energy to compute the CVR factors. Consumers used a method called "Matching Pairs" to compute a CVR factor, which is an important metric for CVR effectiveness. The Matching Pairs method compares weekday load and voltage measurements with reduced voltage (CVR On days) to weekday measurements when normal voltage normal voltage was applied (CVR Off days). Separate calculations were performed for each season because average ambient temperature can have a significant impact on CVR factor. having similar ambient temperature. The resulting CVR factor for Waste Energy Reduction was 0.82, meaning that when voltage is reduced by 1%, load is reduced by 0.82%. The result is consistent with results obtained by other utility companies, which generally fall in the range of 0.7 to 0.8.

  The most common method used in the industry to calculate CVR factors is multiple regression analysis to determine the impact of ambient temperature, voltage, and other factors on load. To confirm the results obtained by Consumers Energy, ESTA performed an independent calculation of CVR factor using regression analysis on the data supplied by Consumers Energy. The result of this analysis was a CVR factor of 0.77 +/- 3.7%. In ESTA's opinion, the results of this independent calculation confirms the accuracy of the Consumers Energy matching pairs method.

  ESTA also used the regression method to determine a CVR factor for Peak Reduction. The Peak Reduction CVR factor is typically significantly different than the Waster Energy Reduction CVR factor because the equipment complement and consumer appliances are different during peak load conditions than the on-line equipment complement during off peak periods. The results of this analysis is a Peak CVR factor of 1.51 with a model error of +/- 3.89%. ESTA is only aware of one utility (undisclosed) that has published a Peak

Demand CVR factor. The published CVR factor was 1.45, which is comparable the results obtained by ESTA.

Later this year, Consumers Energy is planning to use a load forecasting software tool called "MetrixND" (supplied by ITRON) for computing CVR factors. This software tool uses regression analysis to estimate what the load "would have been" with normal voltage for a given day of week an average ambient temperature. ESTA strongly recommends using this type of analysis for determining CVR factors.

CONCLUSIONS

For reasons given above, ESTA concludes that the CVR system software and hardware are well-suited and adequate for conducting the CVR demonstration and that the results obtained for the 50-feeder demonstration can be applied to other Consumers Energy feeders. While the "Matching Pairs" method used by Consumers Energy for computing CVR factor is somewhat unique, the results obtained using this approach match the independent calculations performed by ESTA reasonably well.

Going forward, ESTA encourages Consumers Energy to implement the MetrixND method, not only for estimating peak demand reduction but also for distribution load forecasting in general. ESTA also recommends that Consumers Energy implement a model-driven, ADMS-based approach to CVR because this approach has operational advantages described in this report.

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Purpose of this Document:

This document summarizes the processes and procedures to be used by the project team members.

Ver. No.	Description	Prepared By	Reviewed By
0	Initial Document for Comments	Bob Uluski	Spandan Gandhi
1	Additional sections added	Bob Uluski	Spandan Gandhi
2	Final Draft Version of Report	Bob Uluski	Spandan Gandhi
3	Final Report	Bob Uluski	Spandan Gandhi

1 INTRODUCTION

Conservation Voltage Reduction (CVR) is the practice of reducing service delivery voltage to the lower portion of the acceptable industry range as specified in ANSI Standard C84.1 to reduce energy consumption for waste energy reduction purposes and/or reduce peak electrical demand. Consumers Energy of Jackson, Michigan has conducted a CVR Demonstration Project that included implementing CVR on fifty of its electric distribution feeders that are located throughout the Consumers Energy service territory and has been operating in CVR reduced-voltage mode on alternating days since 2019.

To determine the waste energy and peak demand reduction that can be attributed to voltage reduction, Consumers Energy has conducted a Measurement and Verification (M&V) analysis of the electrical measurement data collected for each of the fifty feeders during the period of CVR alternating-day (aka, “day-on/day-off”) operation. This analysis separates the electrical impacts of voltage reduction from other factors that affect the energy consumption and peak electrical demand, such as naturally varying custom behavior and ambient weather conditions, as well as variations in energy consumption for different hours of the day, days of the week, seasons, and other temporal variations.

The results of the CVR M&V analysis conducted by Consumers Energy indicate that the CVR factor, an important metric for measuring the load-to-voltage sensitivity, ranges from 0.07 to 1.34 for the 50 feeders that Consumers Energy has analyzed. This means that reducing the voltage applied to these electric distribution feeders by 1% will reduce electrical demand on these feeders by between 0.07% and 1.34% without any adverse electrical impacts or load shedding by Consumers Energy customers. The average CVR factor for the 50 CVR circuits is 0.82, which is consistent with CVR factors reported by other electric distribution utilities that have implemented CVR.

Consumers Energy is seeking an independent assessment of its CVR efforts to verify the results to date and assist Consumers Energy in determining whether implementing CVR on additional feeders would be beneficial to Consumers Energy and its customers. In January 2021, Consumers Energy hired ESTA International, Ltd. (ESTA), an independent consulting firm specializing in electric utility automation and energy analysis to review and critique the Consumers Energy CVR project and associated M&V analysis performed by Consumers Energy. This report summarizes the results of this assessment.

2 SCOPE OF THE INDEPENDENT CVR ASSESSMENT

The objective of the consulting assignment is to review and critique the methods used by Consumers Energy to conduct the Day-On/Day-Off CVR demonstration and to assess the method used to analyze the resulting data to determine the CVR factor, which is an important performance metric for CVR. ESTA's assessment included the following items:

- Process for Selecting Feeders. ESTA reviewed and critiqued the method Consumers Energy used to select the feeders on which the CVR demonstration was performed. Ideally, the selected feeders are representative of Consumers Energy feeders where it is practical and economical to implement CVR. That is, the selected feeders should have characteristics that are like the characteristics of the larger set of feeders on which CVR could be implemented. Such characteristics included (but were not limited to) feeder length and configuration, customer mix (residential, commercial, industrial), and location (North, South, East, West).

- CVR Software Algorithms. ESTA reviewed the algorithms and principles of operation of the CVR application software (furnished by the Consumers Energy Distribution Management System (DMS) supplier OSI International (OSII)) to gain a thorough understanding of the approaches used for 24-hour-a-day energy conservation and peak demand reduction.

- Controlled Devices: ESTA reviewed the list of devices that are controlled by the CVR application software, such as feeder voltage regulators and switched feeder capacitor banks. The feeders in question do not include significant penetrations of Distributed Energy Resources (DERs) such as rooftop solar photovoltaic generators which can affect the distribution feeder voltage and reduce the "net" load measured on the feeder. Hence, the DER impact on the results of this study are not significant.

- Data Collected During the Demonstrations: ESTA reviewed the list of electrical measurements collected during the CVR demonstrations to determine if the measurements taken are sufficient for effective operation of the CVR algorithms and determining the CVR factors. ESTA also reviewed the methods used for "data scrubbing" that is needed to eliminate data anomalies, such as bad and missing data, that may produce incorrect results.

- Method of Computing CVR factors for Waste Energy Reduction and Peak Demand Reduction. ESTA reviewed the method used by Consumers Energy to compute the CVR factors. The objective of this activity was to determine if the analytical methods are accurate and consistent with establish industry practices. ESTA compared the Consumers Energy methodology with the analytical approaches described in IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems" to ensure consistency with this standard.

ESTA compared the Consumers Energy approach for each of the items listed above against the approach used by other electric distribution utilities that have similar characteristics to Consumers Energy and have already implemented CVR to determine if the Consumers Energy approach is consistent with best industry practices.

In addition to the assessment of Consumers Energy CVR M&V strategy described above, the project also includes developing a mechanism for predicting what CVR factor would be achieved by implementing CVR on additional feeders. This mechanism is described later in a separate report.

3 QUALIFICATIONS OF ESTA FOR PERFORMING THIS ASSESSMENT

ESTA is uniquely qualified for performing this assessment of Consumers Energy CVR projects and results for reasons stated below:

- ESTA has recently completed a detailed M&V assessment of CVR for Consolidated Edison of New York and has also conducted similar assessments for other utility companies that are similar in size and electrical characteristics to Consumers Energy.

- ESTA's team lead, Mr. Robert Uluski, has served as Chair of the IEEE's Power and Energy Society Task Force on Volt-VAR control and optimization and played a lead role in developing IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems". This standard identifies ways in which electric distribution utilities can evaluate the CVR benefits. This standard was recently approved and published by IEEE. Mr. Uluski has also managed EPRI's "Smart Distribution" research program that included extensive work in laboratory testing to identify load-voltage sensitivity of major electrical appliances and equipment and in load-voltage modelling.

- ESTA's energy analyst, Mr. Spandan Gandhi, has considerable experience in advanced techniques for CVR M&V, including use of neural nets and multiple-regression analysis for modelling and analyzing the impacts of voltage reduction, as well as data scrubbing to identify data anomalies that can distort the M&V results.

- ESTA is a fully independent consulting firm that has no relationships with any system vendor and no vested interest in any commercial product. As a result, our findings, conclusions, and recommendations are completely unbiased by any such relationships.

4 LIST OF ACRONYMS

Following is a list of acronyms and key terms used in this report.

Table 4-1 List of Acronyms

Acronym/ term	Description
AMI	**Advanced Metering Infrastructure -** Facilities for periodically measuring and reporting customer electrical consumption at intervals of an hour or less for billing purposes, and for determining customer consumption patterns. AMI outputs in the form of "last gasp" messages have become a commonly-used mechanism for detecting power outages at individual customer sites. AMI may also be used for detecting low or high voltage conditions and the customer meter and reporting such conditions to the system operator and other persons responsible for outage management.
ANSI	**American National Standards Institute** - a private, non-profit organization that administers and coordinates the U.S. voluntary standards such as C48.1 ("Electric Power Systems Voltage Ratings")
CVR	**Conservation Voltage Reduction** - the process of intentionally reducing the voltage on a distribution circuit to the lower portion of the acceptable voltage range permitted by ANSI standard C84.1.
Day-On/Day-Off	A process of activating a system (such as CVR) on alternating days, and comparing measurements recorded during the "system on" day versus the "system off" day. of comparing
DER	**Distributed Energy Resource -** small scale generators, energy storage units, and controllable loads that are connected to the electric distribution system in close proximity to the load centers. DERs are most commonly used today to supply real and reactive power and curtail load when needed, the objective being to lower dependence on large scale centralized generators and high voltage transmission line as the sole source of supply. In addition, some DERs, such as solar and wind power are renewable energy sources that can help lower greenhouse gas emissions.
DMS	**Distribution Management System** - a computer and communication system the enables electric distribution system operators to monitor and control the distribution system assets and overall electric distribution system performance from the distribution control center.
DR	**Demand Reduction -** a set of processes used to curtail electrical consumption during system emergencies.
DSCADA	**Distribution Supervisory Control and Data Acquisition -** a computer and communication system that enables distribution system operators to monitor and control electric system power apparatus from a control center. The SCADA system is a fully integrated element of the Consumers Energy DMS.
EPRI	**Electric Power Research Institute -** an American independent, nonprofit organization that conducts research and development related to the generation, delivery, and use of electricity to help address challenges in electricity, including reliability, efficiency, affordability, health, safety, and the environment.
ESTA	**ESTA International, Ltd** - an independent consulting firm specializing in the planning, implementation, and the post-implementation analysis of benefits associated with electric utility automation systems. Consumers Energy hired ESTA to perform an independent assessment of its CVR system.

IEEE	**Institute of Electrical and Electronic Engineers -** a large worldwide professional association for electronic engineering and electrical engineering. IEEE is one of several recognized standards-making bodies for electric power systems.
kVAR	**Kilo-volt-ampere-reactive -** A measure of reactive power
LTC	**Load Tap Changer -** A device that automatically regulates the voltage supplied by a substation transformer to the electric distribution feeders. Note that Consumers Energy uses voltage regulators on individual feeders and does not use LTCs.
M&V	**Measurement and Verification** - the process of using measurements to determine actual savings created within an individual facility by an energy management, energy conservation or energy efficiency project or program. M&V is commonly used for estimating the benefits that cannot be measured directly, such as CVR benefits.
OSII	**Open Systems International, Inc, -** the system vendor that supplied the Consumers Energy ADMS that is used to implement CVR.
VVO	**Volt-VAR Optimization -** A software application running on the DMS for improving the efficiency and voltage quality on the electric distribution system. CVR is a subfunction of VVO.

5 ESTA ASSESSMENT OF CONSUMERS ENERGY CVR PROGRAM AND M&V APPROACH

ESTA's assessment of each of the items related to Consumers Energy CVR program is contained in the following sections. The following items are included:

1. Feeder Selection
2. CVR Software Algorithms
3. Controlled Devices
4. Data Collection
5. Method of Computing CVR factor

For each of the items listed above, ESTA has provided the following information:

a) General requirements pertaining to each item.
b) ESTA's understanding of the Consumers Energy approach for each item.
c) Comparison of Consumers Energy approach to best industry practices.
d) ESTA's Findings, conclusions, and overall assessment of Consumers Energy approach to each item.

5.1 FEEDERS SELECTED FOR CVR IMPLEMENTATION

The purpose of this section is to determine if the CVR benefit results for subset of feeders selected for this CVR demonstration project are representative of the CVR benefits that could be gained by implementing CVR on additional feeders.

a) General Requirements and Industry Practice for Feeder Selection

- Feeders should not be "voltage limited". If the service delivery voltage on a given feeder is near the low limit specified in ANSI standard C84.1 at one or more feeder locations during some loading conditions, it may not be possible to reduce voltage when needed. Feeder infrastructure improvements (reconductoring, etc.) may be needed to "flatten" the voltage profile on voltage-limited feeders and provide a suitable operating margin for voltage reduction.

- The customer mix (percentages of residential, commercial, and industrial customers) served by the feeder should be representative of the typical customer mix on other Consumers Energy feeders. Consumers Energy should not select a feeder that has a unique customer mix because results for that feeder may not be indicative of results that may be obtained on other Consumers Energy feeders.

- Voltage and VAR control devices on the feeder should be equipped with remote control capabilities that are needed for the Consumers Energy CVR system (see Section 5.2 for a description of the Consumers Energy CVR system).

- Feeders should have a suitable mechanism for determining the lowest voltage on the feeder. This will provide feedback to the CVR software to ensure voltage is not reduced below the low voltage limit specified in the ANSI standard.

- The feeders selected for CVR demonstration should be widely dispersed throughout the Consumers Energy service territory because the results for feeders in different geographic regions may be different. For example, the results for feeders in the Northern portion of the state may differ from feeders in the Southern portion of the state due to different energy consumption for heating and cooling in these two regions.

b) ESTA's Understanding of the Consumers Energy Approach to Feeder Selection

Consumers Energy used a two-step process for selecting feeders on which to implement CVR during the CVR demonstration project, as described below:

1. During step one of this process, Consumers Energy created a "CVR Potential" circuit pool consisting of approximately 1,700 distribution feeders that are viable "candidates" for CVR implementation. Feeders with the following characteristics were selected for the CVR Potential circuit pool:

    i. Feeder has substation DSCADA telemetry to enable remote monitoring and control capabilities. The Consumers Energy CVR system requires near-real-time DSCADA measurement data, such as reactive power flow, to determine if feeder capacitor bank switching is required. In addition, the CVR Potential circuits must have upgraded line voltage regulators that can be monitored and controlled by DSCADA and the CVR system

    ii. Circuit is not a Dedicated-Customer circuit. Most dedicated customer circuits have unique loading characteristics so the results would not be representative of other Consumers Energy circuits.

    iii. The circuit is not supplied by a delta (3-wire) substation. There are relatively few delta circuits at Consumers Energy, so the CVR results for this type of feeder would not be representative. In addition, the CVR control logic would be more complicated than wye-grounded (4-wire) circuits.

    iv. At least 50% of the customers on the feeder are residential customers. Circuits that primarily serve Commercial and Industrial customers (i.e., % of C/I customers greater than 66%) were excluded from the CVR potential circuits. Feeders with a proportionately higher number of residential customers is common at Consumers Energy, so circuits that serve a high percentage of residential customers are more representative of Consumers Energy distribution feeders.

2. During step 2 of the selection process, Consumers Energy selected 50 of the CVR Potential feeders with characteristics that are most representative of the total set of CVR Potential distribution feeders. Factors considered in selecting the 50 CVR feeders from the CVR Potential list of feeders included customer type breakdown, Archetype, circuit length, customer count, and the percentage of residential customer. ESTA's assessment of each of these feeder selection criteria is provided below:

a) **Customer Type Breakdown:** Customer type breakdown (or the percentages of residential, commercial, and industrial customers on a given feeder) is the primary factor used by Consumers Energy in selecting the CVR feeders from the CVR Potential list. The CVR factor is primarily impacted by the types of customers served by the feeder and the complement of electrical equipment and appliances used by these customers. Therefore, selecting feeders with customer type breakdown that matches the CVR Potential Set is critical for identifying representative feeders for CVR deployment. ESTA computed the customer type breakdown of feeders that were selected for CVR and the CVR Potential group. As seen in below, the differences in percentage mix of customers in the selected set and the CVR Potential set are very small. Therefore, ESTA concludes that the selected CVR circuits are representative of the Consumers Energy CVR potential feeders.

Table 5-1 Comparison by Customer Type Breakdown

	Customer Type Breakdown		
Customer Type	CVR Potential	CVR Selected	Difference
% Commercial	13.3%	11.5%	1.8%
% Industrial	0.2%	0.1%	0.1%
% Residential	84.8%	86.9%	-2.1%

b) **Archetype:** ESTA compared the Archetype breakdown for the selected CVR circuits with the Archetype breakdown for the CVR Potential group, as shown below. The breakdown of feeders by Archetype in the selected CVR set of feeders differs from the CVP Potential set by between 0% and 9%. The most significant difference is that a higher percentage of urban circuits (Archetypes 3 and 4) was selected over rural circuits (Archetypes 5, 6, and 7). In ESTA's opinion, the choice of urban feeders over rural feeders is justified, because urban feeders usually provide higher overall CVR benefits than rural circuits due to shorter length (less voltage drop) and heavier loading (more kWh reduction per unit voltage reduction). ESTA also believes, based on industry experience, that the percentages of rural feeders in the CVR Potential set are too high and that it is unlikely the Consumers Energy would actually add CVR to such a high number of rural circuits due to the lower payback opportunity.

Table 5-2 Comparison by Archetype

Archetype	Archetype Description	CVR Potential	CVR Selected	Difference
0	Circuit has not been assigned an Archetype Value yet	1%	0%	1%
1	Most Large C&I customers, short circuits that are primarily underground, best reliability	2%	25	0%
2	Circuits with greatest mix of customers and high proportion of small C&I, moderate reliability	11%	16%	-5%
3	Urban residential customers, short lines with high customer density, strong reliability, high NPS	14%	18%	-4%
4	Urban customers, longer circuits with high customer density that are more susceptible to outages	27%	36%	-9%
5	Rural circuits primarily in central/south, better reliability than rural circuit peers	20%	12%	8%

6	Rural circuits, low customers per line mile, high frequency of outages and long outage durations	15%	12%	3%
7	Rural customers primarily in the north, longest circuits, worst reliability across the system	10%	4%	6%
8	Radial, unshielded, higher risk HVD groups	0%	0%	0%
9	Core, looped HVD system	0%	0%	0%

c) **Circuit Length:** In general, circuit length does not have a significant impact on the CVR factor. However, since longer feeders will experience a greater voltage drop over the length of the feeder, feeder length impacts the percent voltage reduction that is possible, and therefore, impacts the CVR benefit (lower energy savings and smaller peak shaving possible). Table 5-3 shows the length breakdown of feeders in the selected CVR set of feeders and the CVR Potential circuits. As can be seen in the table, the selected CVR feeder set has a significantly higher percentage of shorter feeders than the CVR Potential set. In ESTA's opinion, this difference is not a matter of concern when computing CVR factor, because, as stated above, feeder length by itself does not impact CVR factor.

Table 5-3 Comparison by Feeder Length

Feeder length (Miles)	CVR Potential	CVR Selected	Difference
0-10	18.6%	40.0%	-21.4%
10-25	31.3%	24.0%	7.3%
25-40	19.2%	24.0%	-4.8%
40-55	14.1%	4.0%	10.1%
56+	16.8%	8.0%	8.8%

d) **Residential Percentage:** ESTA compared the residential percentages in the selected CVR circuits with the residential percentages in the CVR Potential circuit pool. As can be seen in this table, the percentage of residential customers matches reasonably well between the selected CVR circuits and the CVR Potential circuits except for circuits where the percentage of residential customers is less than 80%. Since the Consumer Energy focus is on feeders that have a high percentage of residential customers, this difference should not be a significant problem. Hence, ESTA concludes that here is a good match in residential customer percentages between to the two sets of circuits.

Table 5-4 Comparison by Residential Percentage

% Residential	CVR Potential	CVR Selected	Difference
0-80%	19.4%	8.0%	10.6%
80-85%	19.5%	24.0%	-4.5%
85-90%	30.9%	36.0%	-5.1%
90-100%	30.2%	32.0%	-1.8%

e) Customer Count: As can be seen in Table 5-5, the breakdown of total customer count for the selected feeders matches very well with the breakdown of customer count for the CVR Potential circuits.

Table 5-5 Comparison by Customer Count

Customer Count	CVR Potential	CVR Selected	Difference
0-500	17.7%	18.0%	-0.3%
501-1000	34.2%	32.0%	2.2%
1001-1500	26.6%	24.0%	2.6%
>1500	21.5%	26.0%	-4.5%

f) Other comparisons

- **Region:** Feeder location can have a significant impact on CVR factor, especially for circuits that are in the Northern versus Southern portions of the State of Michigan. The latitude and longitude of the selected CVR circuits is consistent with the Potential CVR circuit pool. The feeders in both the circuit pool and the selected set are primarily located in the southern and central part of the State, with a few outliers in the North. Both sets appear to be split equally between substations in the Eastern and Western parts of the State. Note that the North and south difference is more significant when computing a CVR factor, because energy consumption patterns and associated CVR factors may be different for northern (colder) regions and southern (warmer) regions of the state.

c) **Comparison of Consumers Energy approach to best industry practices**

Several other factors may be considered when selecting circuits for CVR:

a. **Worst performing feeders:** Some utilities have elected to implement CVR (and the broader application Volt-VAR Optimization) on circuits that have historically experienced low power factor. The VVO application can improve power factor and thus reduce losses on these worst performing feeders in addition to accomplishing peak shaving and energy conservation using CVR.

b. **Heavily Loaded Circuits:** Heavily loaded circuits are often selected (provided they are not voltage limited) because the energy savings and peak shaving benefits for a given amount of voltage reduction are greater for a given circuit than a lightly loaded feeder having the same CVR factor.

c. **Groups of Feeders from Same Substation:** Groups of feeders fed off the same substation bus are usually selected for CVR at the same time. This is because voltage reduction actions are performed by a substation load tap changer (LTC) transformer which impacts all feeders that are connected to the low side bus of the transformer. This does not apply to Consumers Energy, which uses individual feeder voltage regulators.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

In ESTA's opinion, the process used by Consumers Energy for selecting feeders for its CVR demonstration far exceeds the feeder selection process used by other utilities that have demonstrated and/or implemented CVR. Most utilities have selected feeders based on a limited set of factors such as the availability of DSCADA and remotely controllable volt-VAR devices (feeder capacitor banks and voltage regulators).

Based on the analysis described above, ESTA concludes that the feeders that have been selected by Consumers Energy for CVR are representative of the broader set of CVR Potential feeders. This conclusion is based primarily on the customer type breakdown which matches well between the two groups of feeders. While there are some differences in other selection criteria between the selected CVR circuits and the CVR Potential group of feeders, these factors in general should not have a major impact on the overall CVR factors.

In the case of Archetype differences between the two sets of feeders, ESTA concludes this is due to having too many rural feeders in the CVR Potential set. If the percentages of rural feeders in the CVR Potential set are reduced, the two sets would have comparable breakdowns by Archetype.

As a result, it is reasonable to conclude that the CVR factors computed for the selected feeders are representative of the results that will be obtained if CVR is applied to other circuits in the CVR Potential circuit pool.

5.2 CVR SOFTWARE ALGORITHMS

In this section, ESTA compared the Consumers Energy CVR system with CVR systems that are that have been implemented by other utilities in North America.

a) General Requirements

a. The CVR system should be able to lower the voltage on selected distribution feeders by a Consumers Energy-specified amount to achieve a reduction in waste energy and/or peak electrical demand.

b. A suitable mechanism should be provided to ensure that the service delivery voltage at all customer meters on the feeder does not go below the limits specified in applicable ANSI standards when CVR is activated. CVR must be transparent to the consumers and must not adversely impact the operation of customer-owned equipment.

c. The CVR system shall be able to operate in either of the following Consumers Energy-selectable modes:
   i. Energy Waste Reduction mode: In this mode, voltage shall be reduced by the specified amount whenever possible, up to 24 hours per day. The objective of this mode is to reduce energy (MWh) consumption without customer load shedding for overall efficiency improvement.

ii. Peak Demand Reduction mode: In Peak Demand Reduction mode, the voltage is lowered for a few hours during which peak demand occurs, with normal voltage applied during other hours. For example, if peak load occurs at 5:00 PM, voltage may be reduced between 4:00PM and 6:00PM, with normal voltage being applied during other hours. The objective of this mode of operation is to reduce the maximum load in megawatts on the feeder. The Peak Demand Reduction algorithms shall ensure that restoration of normal voltage following the CVR peak shaving event does not create a new peak; this can happen when diversity of thermostat-controlled devices is diminished during the voltage reduction period.

d. The CVR algorithms shall ensure that voltage and VAR control devices are properly time coordinated so that "hunting" and contradicting control actions are avoided. For example, control actions by voltage regulators to lower the feeder voltage should not be immediately followed by switched capacitor banks operating to raise the voltage.

e. The CVR algorithms shall not initiate improper or invalid voltage control and VAR control commands when the feeder is reconfigured. Feeder reconfiguration can change the position of capacitor banks and midline voltage regulators relative to the power source which, in turn, can result in improper coordination between devices. Furthermore, CVR shall not attempt to control any switched capacitor bank, voltage regulator, or other VVC device that is tagged out of service.

f. The control strategy for volt-VAR devices shall respect device operating restrictions, such as capacitor bank closing within the capacitor bank discharge time and prevention of "local" regulator over-voltages ("first house" protection).

g. The system shall include mechanisms for monitoring the operation of individual capacitor banks, voltage regulators, controllers, and communication facilities and shall be able to detect failures in any of these components that would prevent the device from operating as needed upon command. Failed components should be excluded from the CVR control strategy.

b) ESTA's understanding of the Consumers Energy approach

a. The Consumers Energy CVR approach is best described as a "rules-based" approach. That is, the CVR logic compares SCADA measurements against predetermined setpoints and then initiates control actions based on "if-then-else" rules. For example, if the reactive power flow to the feeder exceeds a specified setpoint, then switch a capacitor bank on the feeder to the "ON" position; otherwise do nothing. Figure 5-1 depicts a SCADA rules-based solution such as that used by Consumers Energy. Simply stated, when reactive power flow measured at the substation end of the feeder exceeds a pre-determined threshold, the CVR system sends commands to one or more capacitor bank switches, which, in turn, reduces the reactive power flow from the substation.

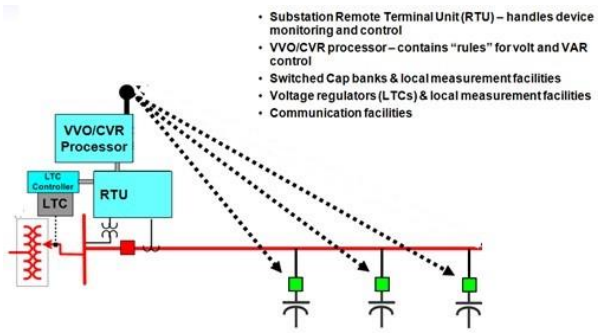


Figure 5-1 SCADA Rules Based CVR System

b. The CVR system setpoints and operating strategies that have been incorporated in the CVR logic have been determined in advance for each feeder by the Consumers Energy Distribution Engineering group using power flow analysis. These setpoints and control strategies have considered "worst case" (e.g., heavy load) conditions to ensure that the recommended CVR control actions will not produce unacceptable, adverse electrical conditions (low or high voltage, equipment overloads, etc.).

c. CVR is currently configured (for demonstration and M&V purposes) to run on alternate days (also known as Day-On/Day-Off strategy). Each day at approximately midnight, the CVR system automatically switches to the opposite operating mode (reduced voltage mode to normal voltage mode or normal voltage mode to reduced voltage mode).

d. To provide proper time coordination of voltage regulators and capacitor banks and avoid "hunting", Consumers Energy has incorporated the following rules in its CVR system:

- **i.** Capacitor banks are controlled first, followed by voltage regulators.
- **ii.** Device coordination is accomplished using different pre-determined time delays on each device.
- **iii.** Capacitor banks that are closest to the load center (i.e., furthest from the source) are switched on first. This allows upstream capacitor banks to see the change in reactive power flow caused by downstream capacitor banks switching before operating to prevent overcompensation.
- **iv.** Voltage regulator control actions (raise or lower tap position) are first executed on substation voltage regulators, followed by the control of midline voltage regulators.

e. Capacitor bank switching is initiated by the CVR software whenever the reactive power flow measured at the substation end of the feeder exceeds a predetermined amount (typically set at +/-

400 kVAR). The CVR system selects the capacitor bank that is closest to the load center (furthest from the substation) whose size in kVAR does not exceed the measured amount. After this capacitor bank is switched, the logic is repeated until no additional capacitor bank switching is possible.

f. If the measured VAR flow at the substation end of the feeder becomes negative (reactive power flow back into the substation (i.e., leading power factor)), the CVR software will switch off capacitor banks using similar logic to that described above (i.e., largest capacitor banks that are closest to the load center switched off first).

g. After a predetermined delay to allow capacitor bank switching to complete, voltage regulator operation is permitted using the predetermined Energy Waste Reduction settings. If midline voltage regulators are present, the time delay for these voltage regulators will be larger than the time delay for the substation voltage regulator for proper time coordination of substation and midline devices.

h. Peak Demand reduction is activated manually by the Distribution Operator during periods when peak shaving is required, such as during Merchant Operations demand reduction (DR) events. The logic used by Peak Demand Reduction CVR logic for controlling capacitor banks and voltage regulators is the same as Energy Waste Reduction. However, the logic is triggered at the start of the event (an hour or two before the system peak) and returned to normal an hour or two following the system peak.

i. If the feeder is reconfigured for any reason, the CVR logic is disabled to avoid switching capacitor banks that are no longer connected to its normal feeder and to avoid improper time coordination due to having a different location of a device relative to its source. It is not practical to incorporate additional rules to handle all the possible switching combinations using simple Boolean logic, and maintenance of such complex logic would be labor intensive. When the CVR system is disabled, the distribution voltage and reactive power control strategy reverts to local autonomous control performed by the individual device controllers.

j. Customer voltages reported by the Consumers Energy Advanced Metering Infrastructure (AMI) are checked the following day to determine if any low or high voltage deviations occurred during the previous day's voltage reduction actions. If frequent voltage deviations are observed for a given customer meter or location, the voltage regulator and capacitor banks settings for the associated feeder are adjusted as needed to avoid reoccurrence of these deviations. If necessary, feeder infrastructure improvements (e.g., reconductoring) may be implemented to eliminate significant voltage deviations that cannot be mitigated by setting changes alone.

c) Comparison of Consumers Energy approach to best industry practices

a. Most of the existing CVR solutions that today's electric utilities have implemented are SCADA "rule-based" systems that use logic like the Consumers Energy CVR system. That is, control decisions are based on "if-then-else" (Boolean) logic performed on measurements received from the utility's distribution SCADA system.

b. Some utilities use proprietary CVR solutions offered by vendors such as Utilidata, Dominion Voltage, Eaton IVVC, and other system vendors. These proprietary solutions are often considerably more expensive per substation then SCADA rules-based solutions due to the sophisticated algorithms and additional hardware needed to identify and implement required control actions. Incremental benefits offered by these systems include the potential for fewer voltage regulator tap position changes and nearly-real-time voltage feedback from strategic feeder locations for rapid detection and correction of voltage deviations. Note that the solution type does not impact the CVR factor, which is determined primarily by the electrical equipment and appliances used on a feeder. Like the Consumers Energy system, these proprietary solutions are often switched off when feeder reconfiguration occurs.

c. A growing trend is the deployment of "model-driven" Volt-VAR Optimization (VVO) solutions that are incorporated in the electric utility's Advanced Distribution Management System (ADMS). These ADMS solutions perform power flow analysis on an as-switched (as operated) electrical model to determine the "optimal" set of voltage and reactive power control actions to achieve one or more selected operating objectives. Selectable operating objectives may include reduce losses, conserve energy, peak shaving, voltage profile improvement, reactive power support to the bulk power grid, minimize use of high maintenance equipment, or a weighted combination of the above. Besides providing selectable business objectives, model driven solutions can provide the following additional benefits:

    i. The power flow solution automatically provides supplies continuous feedback about the voltage at all points on the feeder so that low or high voltage conditions are rapidly detected and corrected.

    ii. Model-driven solutions adapt automatically when feeder reconfiguration occurs so that CVR does not have to be shut down. While the results for a reconfigured feeder may not represent "optimal" results, they do provide the best possible CVR solution with no voltage deviations given the current as-switched condition of the feeder.

    iii. Model driven solutions are better able to accommodate the impacts of distributed energy resources (DERs) and, where possible, leverage the opportunities offered by DERs, such as using "smart" inverters to supply reactive power. Currently, the DER penetration level is not high enough to warrant consideration of these devices in the CVR system. However, if penetration level rises in the future, a model-driven strategy may be the most effective approach.

    The benefits listed above come at a high price (including implementation costs and O&M costs). However, since Consumers Energy is currently implementing an ADMS that will have the necessary model and application software, a cost-effective model-driven solution may be possible Consumers Energy in the future.

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. The Consumers Energy SCADA rules-based approach is a very effective solution that has achieved significant Waste Energy Reduction benefits and Peak Demand reductions benefits for Consumers Energy customers and Consumers Energy itself at a reasonable cost.

b. The rules-based approach is well-suited for "proof of concept" as well as achieving actual operational benefits.

c. As discussed above, there are two significant limitations of the rules-based approach used by Consumers Energy: inability to handle feeder reconfiguration and lack of immediate voltage feedback when low voltage conditions occur at some customer meters.

    i. In the future, feeder reconfiguration may occur more frequently than before as Consumers Energy introduces new ADMS applications, such as Fault Location, Isolation, and Service Restoration (FLISR). ESTA assumes that when a feeder is reconfigured for any reason, Consumers Energy will endeavor to restore the feeder to its normal configuration as soon as possible. Therefore, the period that CVR will be disabled is minimized. However, in the long run, Consumers Energy should consider implementing CVR on its new ADMS to avoid a complete shutdown of the CVR application when feeder reconfiguration occurs.

    ii. Due to the lack of near-real-time voltage feedback, a small number of customers may at times experience voltage at the low end of the standard voltage range. Such rare voltage deviations are detected manually by reviewing AMI data the day after a voltage reduction event. Upon detecting the problem, Consumers Energy may alter the CVR settings and, if necessary, plan for infrastructure improvements for more serious and severe problems. This method of low voltage detection is acceptable if the voltage deviation is infrequent, relatively small (less than 2-3% below the minimum voltage) and is promptly corrected. However, failure to deal with severe low voltage conditions on a timely basis can result in customer voltage complaints and, in the worst case, damage to customer-owned equipment.

    This problem can be addressed by adding bellwether voltage meters at feeder extremities and other strategic locations and incorporating measurements from these meters in the CVR logic. This is shown in Figure 5-2 below. If possible, near-real-time low voltage alarms from AMI meters can also be incorporated in the logic. The ADMS model-driven solution provides another possible remedy because the ADMS Powerflow computes the voltage at all feeder locations on a continuous basis and will automatically block control actions that would produce voltage deviations.

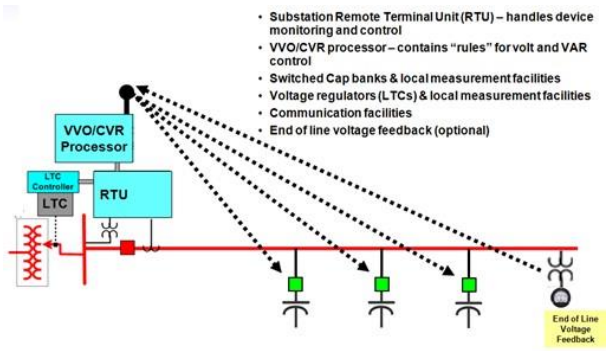


Figure 5-2 Rules-Based CVR with Voltage Feedback

Note that having continuous feedback on feeder voltage level will enable Consumers Energy to operate with a smaller voltage margin to the low voltage threshold, thus enabling Consumers Energy to obtain greater Waste Reduction and Peak Demand reduction benefits.

5.3 CONTROLLED DEVICES

This section contains an assessment of the devices controlled by the Consumers Energy CVR system.

a) General Requirements

The CVR solution should be able to manage the operation of all controllable devices that affect the reactive power flow and voltage profile on the feeder. Controlled devices should include (as a minimum):

i. Voltage regulators located at the head end of the feeder and at mid-line locations (Consumers Energy has few midline regulators on its distribution system and none of these devices on the CVR demonstration feeders)

ii. All switched capacitor banks located out on the feeders.

In the future, the CVR system may need to control additional devices:

iii. ""Edge of network" devices (if any) such as smart inverters and distributed VAR sources located on the secondary side of distribution service transformers.

iv. Distributed energy resources (energy storage, distributed generators with smart inverters, etc.) that are capable of supplying or absorbing real and reactive power on demand.

b) ESTA's understanding of the Consumers Energy approach

a. Consumers Energy CVR system manages the operation of distribution voltage regulators and switched capacitor banks that are installed on the electric distribution system.

b. There are no "Edge of Network" or controllable DERs that are connected to the electric distribution system.

c. Consumers Energy uses separate voltage regulators on all individual feeders. This provides a significant advantage over most other utilities that have multiple feeders connected to a common voltage-controlled substation bus. Consumers Energy can implement different control actions as needed on all feeders out of a single substation without being concerned that a CVR control action will benefit one feeder and adversely impact another feeder that is connected to the same substation. For example, if one substation feeder is voltage limited, it would not be possible to lower the voltage on the remaining feeders connected to the same bus. However, with individual feeder voltage controls, it is possible to lower voltage on feeders that are not voltage limited while retaining the normal voltage or boosting the voltage on the feeder that is voltage limited.

c) Comparison of Consumers Energy approach to best industry practices

The list of controllable volt-VAR devices by Consumers Energy is consistent with devices that are installed on most electric distribution circuits operated by electric distribution utilities.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

a. The list of controllable volt-VAR devices on Consumers Energy distribution feeders meets and, in some ways (e.g., control of voltage on individual feeder voltages), exceeds the control requirements for CVR.

b. While Consumers Energy does not currently have any "edge of network" devices, it should be possible to add these devices in the future to either a rules-based solution or ADMS model-driven solution, if needs arise (e.g., widespread electric vehicle charger deployment, addition of significant penetration of rooftop solar PV generators).

5.4 MEASUREMENT DATA COLLECTED

a) General Requirements

a. The CVR system should acquire key measurement data and equipment status information via distribution SCADA or other mechanism on a continuous "near-real-time" basis. In other words, up-to-date field information should be supplied to the CVR system at least once every 15 minutes.

b. Information supplied to the CVR system should include (as a minimum):

i. Real and reactive power flow (A, B, and C phases) measured at the substation end of the feeder.

ii. Voltage measurements (A, B, C phases) at the substation end of the feeder

iii. Voltage measurement at strategic locations on the feeder (e.g., feeder extremities)

iv. Operating status of all equipment that is monitored and controlled by CVR. This includes feeder circuit breaker and recloser status, open/closed position of all capacitor bank switches, and capacitor bank protective devices (e.g., neutral shift detection)

v. Voltage regulator tap position (if available)

c. Data "scrubbing" should be performed to identify and eliminate all data anomalies (e.g., unreasonable values, "stale" information that has not changed for an extended period) in the supplied data. Failure to detect and eliminate these data problems can result in incorrect results.

b) ESTA's understanding of the Consumers Energy approach

a. Consumers provided data from all 50 feeders on which CVR was implemented. On twenty of these feeders, demand response CVR was also conducted on selected peak load days in 2020.

b. List of variables: CVR Status, Timestamp, Phase –X kW Load, Phase –Y kW Load, Phase –Z kW Load, Phase-X secondary load voltage, Phase-Y secondary load voltage, Phase-Z secondary load voltage, Temperature, Total kW Load, Average Sub Voltage

c. Duration: varies for each feeder. "010007" feeder was the first feeder to go under voltage reduction program on August 7, 2019 and "065502" feeder was the last feeder, CVR starting on December 8, 2020. The CVR program continued until April 2021.

d. Resolution: SCADA (Supervisory Control and Data Acquisition) data provided to ESTA was recorded at a 15 min interval.

e. Data Scrubbing: A significant amount of data was scrubbed for several reasons including telemetry issues, Application issues, holidays, and data errors. Scrubbed data was excluded from this analysis.

c) Comparison of Consumers Energy approach to best industry practices

The list of measurement and equipment status information in the Consumers Energy system is consistent with devices that are installed on most electric distribution circuits operated by electric distribution utilities. However, most solutions at other utilities provide a means of obtaining near-real-time voltage feedback from AMI meters or bellwether line voltmeters. Consumers Energy does not receive such voltage feedback on a continuous basis. However, day-after voltage measurements from AMI are reviewed daily by Consumers Energy to detect any voltage problems which are subsequently corrected.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

a. The data measurements supplied to the Consumers Energy CVR system provide the minimum amount of information that is needed for operation of the CVR system and for performing M&V of the CVR results.

b. Some data "scrubbing" was needed to eliminate data anomalies, such as "stale" data that remains constant for an extended period. However, enough data remained for performing the M&V after removing suspect data.

c. ESTA notes that the need for data scrubbing during M&V analysis is common in the industry and that the amount of data scrubbing was far less for Consumers Energy's data than the data scrubbing required for M&V purposes at other electric utilities.

d. While Consumers Energy does not currently have any "edge of network" devices, it should be possible to add these devices in the future to either a rules-based solution or ADMS model-driven solution, if needs arise (e.g., widespread electric vehicle charger deployment, addition of significant penetration of rooftop solar PV generators).

5.5 METHOD OF COMPUTING CVR FACTOR

The methods used to compute CVR factor for waste energy reduction and peak demand reduction are slightly different. Therefore, separate sections are provided below for the two operating modes.

5.5.1 CVR FACTOR FOR WASTE ENERGY REDUCTION

a) General Requirements

- M&V analysis must determine the CVR factor for individual distribution feeders with an accuracy of +/- 5% or better. CVR factor is the percentage change in power or energy attributable to voltage reduction divided by the percentage reduction in voltage.
- Separate CVR factors must be provided for Energy Waste reduction and Peak Demand reduction
- Measurement and Verification (M&V) Analysis must separate the electrical impact of voltage reduction on power or energy consumption from other factors that impact power or energy consumption. Other factors include:
  i. Ambient weather conditions and season
  ii. Day of week, time of day

- CVR voltage and load reductions were calculated by averaging all of the day "CVR On"/"CVR Off" readings and comparing the difference.

- $$CVR\ factor = \frac{(Avg.\text{ CVR Off } Load - Avg.CVR\ On\ Load) / Avg.\text{ CVR Off } Load}{(Avg.\text{ CVR Off } Voltage - Avg.CVR\ On\ Voltage) / Avg.\text{ CVR Off } Voltage}$$

b) ESTA's understanding of the Consumers Energy approach

- Consumers Energy uses a "Matching Pairs" concept for its CVR M&V analysis. The process involved comparing load measurements for a set of days on which CVR was "on" (voltage reduced) with a set of load measurements for an equal number of days when CVR was "off" (normal voltage applied).

- CVR-On data sets were compared with CVR-Off data sets having "similar" characteristics. "Similar" days are either weekdays or weekends having similar average daily temperatures:

    - **Weekdays versus Weekends:** Data sets containing weekday loads were compared with other weekdays. Weekend days were compared with other weekend days.

    - **Temperature Range:** Each data set contained load data for each "season" which includes days on which the average temperature was within a specified range. Consumers Energy determined the range of seasons based on predetermined temperature thresholds. For example, when mean temperature of the day goes beyond 65 F consistent for consecutive days, "Summer" season is considered to have begun, and it continues till threshold for "Fall" season is reached. Based on this following season ranges were identified: Start Day, End Day
        i. 2019 Summer: 8/7 to 10/1
        ii. 2019 Fall: 10/2 to 11/5
        iii. 2019/2020 Winter: 11/6 to 3/24
        iv. 2020 Spring: 3/25 to 5/22
        v. 2020 Summer: 5/23 to 9/6
        vi. 2020 Fall: 9/7 to 11/20
        vii. 2020/2021 Winter: 11/21 to 3/9

.

- Each CVR On day has a corresponding CVR Off day with the same day type (weekday or weekend) and season. An equal number of CVR On days and CVR Off days is needed for this analysis. If the number of days in each category is not the same, the M&V algorithm will exclude days from the category with higher number of days by first taking the mean load and temperature of each day and whole day and season category and eliminate the day with mean farthest from category mean.

- Once the CVR on-off cycle is completed, the load and voltage value are collected for each feeder over a resolution of 15 mins. The CVR factor is calculated by averaging all days with "CVR On"/"CVR Off" readings and comparing the difference, as shown below:

$$CVR\ factor = \frac{(Avg.\ \text{CVR Off}\ Load - Avg.\ CVR\ On\ Load) \Big/ Avg.\ \text{CVR Off}\ Load}{(Avg.\ \text{CVR Off}\ Voltage - Avg.\ CVR\ On\ Voltage) \Big/ Avg.\ \text{CVR Off}\ Voltage}$$

- Using this calculation, Consumers Energy found that from date 8/7/2019 to 12/31/2020, for all the CVR experiments conducted on all 50 feeders, the average CVR factor they were able achieve

was 0.82, with it ranging from 1.34 to 0.07. The average voltage drop was 2.31%, while the average load drop was 1.9%.

- The Consumers Energy M&V approach assumes that the primary factors other than voltage that affect the average load on a given feeder are day of week (i.e., weekday versus weekend, holidays excluded), average ambient temperature, and season.

- Based on this assumption, the loading on a selected feeder will be the same on all weekdays in each season that have the same daily average temperature if the voltage is the same. For example, the loading on a selected feeder for two summer weekdays (Monday through Friday) that have the same average temperature will be approximately the same if normal voltage is supplied to the feeder.

- As a result of the assumptions listed above, any loading difference on two summer days with the same average temperature can be attributed to differences in applied voltage.

- To compute the CVR factor for a given feeder, Consumers Energy performed the following tasks:

    - Defined seasons as a consecutive set of days where daily average temperature is within a given range, and created separate files containing load and voltage data for each season.

    - Separated the above seasonal data files into two files: one containing only weekdays (Monday through Friday) and one containing only Weekends (Saturday and Sunday). Loading for special days and holidays was excluded from the analysis.

    - Separated the weekday file and the weekend file into two files: one file contains only loading data when voltage was reduced (CVR on) and one file containing loading data when voltage was not reduced.

    - The next step in the process was to ensure that number of “CVR On” days in each season’s weekday file is the same as the number of “CVR Off” days in each season’s weekday file.

    - Consumers Energy then computed the average daily load and the average voltage using data in the “CVR On” file and the average daily load and voltage using data from the “CVR Off” file. Then Consumers Energy computed the percentage difference in average daily load and average voltage between the On days and Off days

    - The CVR factor for the feeder in the given season is the percentage difference in feeder loading for CVR On and CVR Off days divided by the percentage difference in average voltage for CVR On days and CVR off days.

- CVR factors were computed as described above for each of the fifty feeders in the CVR demonstration. The results are shown in . As seen in T 5-6, CVR factor varied from feeder to feeder ranging from 0.07 to 1.34, with the average CVR factor for this group of feeders being 0.82.

- In 2021, Consumers Energy plans to use a new Predictive software tool called MetrixND to forecast what the load "would have been" had voltage not been reduced (i.e., normal voltage applied). Consumers Energy plans to use this load forecasting tool to derive a CVR factor for each tested circuit.

Table 5-6 CVR Factors for Each Feeder using "Matching Pairs" Method

Feeder ID	Substation	Circuit	CVR Enabled Date	Consumers CVRf
1903	Roberts Street	Bender	6/10/2020	0.99
7303	Milton	Federal Screw	1/22/2020	0.86
10007	Wealthy Street	Godfrey	8/7/2019	0.79
10106	Fremont	Reeman	11/6/2019	0.70
14301	Spring Lake	Spring Lake	3/4/2020	0.79
17301	Meridian	Towar Gardens	10/9/2019	0.87
21801	Wildwood	Yardman	5/27/2020	0.41
21802	Wildwood	Macklin	11/20/2019	1.16
23508	Beals Road	Godwin Heights	1/15/2020	0.82
28802	Michigan Center	Ballard	5/13/2020	0.90
29203	Manchester	Duncan	5/14/2020	1.34
29901	Norton	Pontaluna Road	1/22/2020	1.06
29902	Norton	Hile Road	5/13/2020	1.31
31803	East Muskegon	Quarterline Road	2/12/2020	0.84
34201	Hickory	Gateway	1/29/2020	0.07
34401	Hull Street	Lime Lake	11/13/2019	0.86
36902	Cooley	North Street	3/18/2020	0.75
41303	Terrace	Spring	10/23/2019	0.74
43502	Lake Odessa	Industrial	8/21/2019	0.72
48301	Aubil Lake	Towers	5/20/2020	0.78
50403	Oliver	King Street	1/8/2020	0.59
56802	Ramona	Blodgett	10/30/2019	0.49
60701	Getty	Marquette	6/3/2020	1.13
63403	Kilgore	Mount Everest	6/10/2020	0.99
63404	Kilgore	Timberlane	2/5/2020	0.88
63802	Neeley	Doster	5/27/2020	0.94
65502	O-at-ka	East Bay	8/12/2020	1.29
69902	Walker	Rosalie	2/12/2020	0.82
70305	Ingham	Greenwood Park	7/2/2020	1.24
72702	Burlingame	Michael	2/5/2020	0.82

73101	Mona Lake	Airport	3/18/2020	0.82
81502	Harper Road	Eifert	6/24/2020	1.33
90701	Club	Adventure	5/20/2020	0.63
90802	Oak Street	West Ganson	1/15/2020	0.66
101902	Midway	Naomi	1/8/2020	0.59
102701	Savidge	Boom Road	3/4/2020	0.74
110802	Williams	Cresent	2/19/2020	0.81
118401	Newburg	Bancroft	8/14/2019	0.92
118403	Newburg	Shiatown	5/20/2020	0.63
128802	Bennett	Jolly Road	5/27/2020	0.43
128803	Bennett	Dobie Road	2/19/2020	0.76
130301	West Road	Wood Road	3/11/2020	0.84
133501	Tallman	Wacousta	6/3/2020	1.34
133502	Tallman	Clark Road	10/16/2019	0.73
148501	Crahen	Greenbrier	5/14/2020	0.54
149502	Eleventh Street	Starr Road	6/17/2020	0.76
150002	Withey Lake	Henderson	6/17/2020	0.63
154301	Harvard Lake	Harvard Lake	6/3/2020	0.79
154901	Birchwood	Laraway Lake	3/11/2020	0.67
157802	Tremaine	Keefer Road	1/29/2020	0.56
Total				**0.82**

c) Comparison of Consumers Energy approach to best industry practices

- Regression Analysis of Day-On/Day-Off data
  - The CVR M&V approach that is most widely used in the electric utility industry involves multiple regression analysis to determine the relationship between various independent variables that typically impact load (ambient temperature, day of week, voltage level, etc.) and load.
  - The analysis is applied to data collected during CVR Day-On/Day-Off or CVR week on/week off demonstrations like the CVR pilot demonstrations conducted by Consumers Energy.
  - The resulting regression formula is used to estimate what the feeder load "would have been" on a "CVR On" day (reduced voltage) if the voltage had not been reduced.
  - The CVR factor can then be determined by comparing the actual measured loads for CVR On days against the estimated load computed using the regression formula.
- ESTA performed a regression analysis as described above using the day-on/day-off data supplied by Consumers Energy. The results of this analysis are summarized in Table 5-7 below. The CVR

factors computed using regression analysis and the Consumers Energy "matching pairs" approach was somewhat different for individual feeders. The CVR factors computed for individual feeders using regression analysis ranged from 0.2 to 1.41 (compared with the range of .07 to 1.34 for matching pairs). However, the overall average CVR factor for the entire set of CVR feeders computed using the two approaches was similar: 0.77 to regression analysis and 0.82 for matching pairs. Note that the regression analysis performed by ESTA has a modelling error of +/- 3.7%. So the range of the regression analysis is 0.74 to 0.79.

- ESTA finds that the results obtained using the two independent and significantly different approaches are comparable and consistent with results published by other electric utilities. As a result, ESTA concludes that the approach used by Consumers Energy for computing the CVR factors for Waste Energy Reduction is valid and accurate.

Table 5-7 Comparison of Feeder CVR Factors Using Matching Pairs and Regression Analysis

Feeder ID	Substation	Circuit	CVR Enabled Date	Consumers CVRf	Model Error Rate	Model CVRf	Difference
1903	Roberts Street	Bender	6/10/2020	0.99	5.49%	1.13	14%
7303	Milton	Federal Screw	1/22/2020	0.86	4.10%	0.65	25%
10007	Wealthy Street	Godfrey	8/7/2019	0.79	3.27%	0.7	11%
10106	Fremont	Reeman	11/6/2019	0.70	3.19%	0.56	20%
14301	Spring Lake	Spring Lake	3/4/2020	0.79	3.81%	1.01	28%
17301	Meridian	Towar Gardens	10/9/2019	0.87	4.42%	0.97	12%
21801	Wildwood	Yardman	5/27/2020	0.41	3.84%	0.27	34%
21802	Wildwood	Macklin	11/20/2019	1.16	3.72%	0.83	28%
23508	Beals Road	Godwin Heights	1/15/2020	0.82	3.95%	1.08	31%
28802	Michigan Center	Ballard	5/13/2020	0.90	4.08%	1	11%
29203	Manchester	Duncan	5/14/2020	1.34	4.07%	1.03	23%
29901	Norton	Pontaluna Road	1/22/2020	1.06	3.06%	1.24	17%
29902	Norton	Hile Road	5/13/2020	1.31	3.94%	1.3	1%
31803	East Muskegon	Quarterline Road	2/12/2020	0.84	3.53%	0.81	4%
34201	Hickory	Gateway	1/29/2020	0.07	4.21%	0.21	202%
34401	Hull Street	Lime Lake	11/13/2019	0.86	4.26%	1.09	27%
36902	Cooley	North Street	3/18/2020	0.75	2.92%	0.66	12%
41303	Terrace	Spring	10/23/2019	0.74	2.95%	0.74	0%
43502	Lake Odessa	Industrial	8/21/2019	0.72	3.29%	0.74	2%
48301	Aubil Lake	Towers	5/20/2020	0.78	4.84%	0.71	9%
50403	Oliver	King Street	1/8/2020	0.59	3.82%	0.46	22%
56802	Ramona	Blodgett	10/30/2019	0.49	2.12%	0.42	15%
60701	Getty	Marquette	6/3/2020	1.13	3.65%	0.81	28%

63403	Kilgore	Mount Everest	6/10/2020	0.99	3.81%	0.5	50%
63404	Kilgore	Timberlane	2/5/2020	0.88	4.28%	0.53	39%
63802	Neeley	Doster	5/27/2020	0.94	4.33%	0.9	4%
65502	O-at-ka	East Bay	8/12/2020	1.29	3.21%	0.75	42%
69902	Walker	Rosalie	2/12/2020	0.82	3.33%	0.99	21%
70305	Ingham	Greenwood Park	7/2/2020	1.24	3.12%	0.65	47%
72702	Burlingame	Michael	2/5/2020	0.82	3.45%	0.51	37%
73101	Mona Lake	Airport	3/18/2020	0.82	3.55%	0.8	2%
81502	Harper Road	Eifert	6/24/2020	1.33	5.94%	0.99	25%
90701	Club	Adventure	5/20/2020	0.63	4.39%	0.66	6%
90802	Oak Street	West Ganson	1/15/2020	0.66	3.35%	0.71	8%
101902	Midway	Naomi	1/8/2020	0.59	3.67%	0.2	66%
102701	Savidge	Boom Road	3/4/2020	0.74	3.84%	0.42	43%
110802	Williams	Cresent	2/19/2020	0.81	3.59%	0.73	10%
118401	Newburg	Bancroft	8/14/2019	0.92	3.03%	0.71	23%
118403	Newburg	Shiatown	5/20/2020	0.63	3.93%	0.69	9%
128802	Bennett	Jolly Road	5/27/2020	0.43	4.50%	0.88	106%
128803	Bennett	Dobie Road	2/19/2020	0.76	3.26%	0.64	16%
130301	West Road	Wood Road	3/11/2020	0.84	3.46%	0.32	62%
133501	Tallman	Wacousta	6/3/2020	1.34	6.28%	1.09	19%
133502	Tallman	Clark Road	10/16/2019	0.73	4.37%	0.6	18%
148501	Crahen	Greenbrier	5/14/2020	0.54	3.85%	0.84	54%
149502	Eleventh Street	Starr Road	6/17/2020	0.76	4.33%	1.07	40%
150002	Withey Lake	Henderson	6/17/2020	0.63	5.33%	1.41	124%
154301	Harvard Lake	Harvard Lake	6/3/2020	0.79	4.47%	0.92	16%
154901	Birchwood	Laraway Lake	3/11/2020	0.67	3.48%	0.61	9%
157802	Tremaine	Keefer Road	1/29/2020	0.56	4.29%	0.88	57%
Total				**0.82**	**3.90%**	**0.77**	**31%**

- Neural Net Methodology
  - ESTA has used neural net methodology to compute CVR factors with an accuracy of 2% or better, However, this method requires several years of data to "train" a model that is used to predict what the load would have been on a future date if voltage had not been reduced. Note that this approach may not be possible at this time for Consumers Energy because the CVR pilot projects have been conducted during the pandemic, which has exhibited considerably different loading patterns due to work-at-home restrictions.

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. ESTA has reviewed the Consumers Energy "Matching Pairs" M&V method and offers the following comments and conclusions.

b. A major assumption on which the "Matching Pairs" analysis is based is that differences in average feeder loading observed in the day-on and day-off data sets are primarily due to voltage differences rather than differences in ambient temperature. For this assumption to be valid, the load must remain nearly constant with normal voltage applied for the days in each season.

c. ESTA examined the relationship between load and ambient temperature and observed the expected relation between load and temperature for Consumers Energy CVR feeders. Figure 5-3 contains graph showing the relationship between load and ambient temperature for one of the Consumers Energy feeders in the Selected CVR feeders. As expected, the relationship is a bathtub shaped curve with sloping lines that are different for each feeder. ESTA used the bathtub curve sloping lines for each feeder to determine the approximate change of load given the range of ambient temperatures observed.

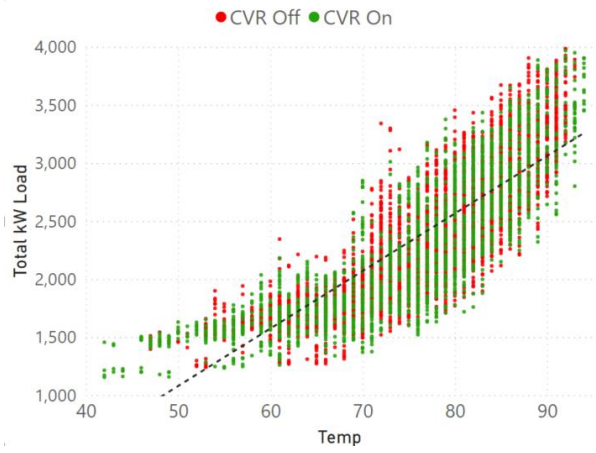


Figure 5-3 Variation of Load with Temperature on a CVR feeder

d. The results showed that for most feeders, the feeder load changed by only a small percentage amount for the range of temperatures included in the "seasonal" data sets. Table 5-8 shows the approximate change in load that can be attributed to the temperature differences in the matching pairs data sets for weekdays in summer. Hence, ESTA concludes that average load variations in the Day-On and Day-Off datasets are primarily due to voltage reduction. This is shown in the table below for summer weekdays:

Table 5-8 Expected Change in Weekday Load for Temperature Variation in Summer

Feeder ID	Day Type	CVR Temp On	CVR Temp Off	Load Change per F	Load variation due to Temp
1903	Weekday	72.75	72.95	1.20%	-0.25%
1903	Weekend	69.93	72.28	1.21%	-2.83%
7303	Weekend	62.93	62.02	0.45%	0.41%
7303	Weekday	64.03	62.32	-0.08%	-0.14%
10007	Weekday	73.40	72.95	1.60%	0.71%
10007	Weekend	71.72	70.96	1.80%	1.35%
10106	Weekend	63.85	64.49	0.76%	-0.48%
10106	Weekday	68.05	65.97	0.49%	1.02%
14301	Weekend	71.96	71.53	3.06%	1.31%
14301	Weekday	74.25	74.09	3.16%	0.51%
21801	Weekday	72.67	73.19	1.95%	-1.00%
21801	Weekend	70.78	70.45	2.42%	0.80%
21802	Weekend	70.16	70.08	3.07%	0.24%
21802	Weekday	72.87	73.44	2.99%	-1.71%
23508	Weekend	71.41	71.82	1.97%	-0.81%
23508	Weekday	73.18	73.47	1.39%	-0.40%
28802	Weekend	70.48	70.66	3.15%	-0.55%
28802	Weekday	72.72	73.05	3.17%	-1.06%
29203	Weekend	64.99	64.81	0.86%	0.16%
29203	Weekday	70.16	67.62	0.69%	1.75%
29901	Weekend	67.19	70.77	1.93%	-6.91%
29901	Weekday	71.35	71.19	3.19%	0.53%
29902	Weekend	71.77	72.13	3.30%	-1.20%
29902	Weekday	73.54	73.89	3.55%	-1.26%
31803	Weekend	71.85	71.53	2.43%	0.78%
31803	Weekday	74.09	73.99	2.68%	0.26%
34201	Weekend	73.97	66.21	1.57%	12.18%
34201	Weekday	73.97	75.11	0.81%	-0.92%
34401	Weekend	72.47	72.14	2.91%	0.94%
34401	Weekday	73.75	74.20	2.78%	-1.26%
36902	Weekend	73.30	72.43	2.40%	2.10%
36902	Weekday	75.73	75.54	2.18%	0.41%
41303	Weekend	71.95	70.55	2.13%	2.98%
41303	Weekday	73.92	73.75	2.09%	0.34%
43502	Weekend	64.03	67.83	0.83%	-3.16%
43502	Weekday	65.77	66.23	0.40%	-0.19%
48301	Weekend	71.56	71.20	2.80%	0.99%
48301	Weekday	73.83	74.05	2.54%	-0.56%
50403	Weekend	63.91	64.08	0.53%	-0.09%
50403	Weekday	65.73	64.38	0.27%	0.36%

56802	Weekend	72.09	71.36	1.58%	1.16%
56802	Weekday	74.47	74.73	1.49%	-0.40%
60701	Weekday	71.31	70.41	2.11%	1.89%
60701	Weekend	68.43	71.97	2.28%	-8.10%
63403	Weekday	75.79	75.81	2.93%	-0.04%
63403	Weekend	74.24	75.15	3.04%	-2.78%
63404	Weekend	73.17	74.80	2.15%	-3.50%
63404	Weekday	75.19	76.15	2.16%	-2.08%
63802	Weekday	75.20	75.85	3.17%	-2.06%
63802	Weekend	72.98	73.45	3.01%	-1.40%
65502	Weekday	71.83	73.15	2.56%	-3.38%
65502	Weekend	67.69	70.88	2.41%	-7.69%
69902	Weekend	71.50	70.96	3.07%	1.65%
69902	Weekday	73.47	74.26	3.23%	-2.57%
70305	Weekday	73.03	73.80	1.70%	-1.31%
70305	Weekend	69.03	74.03	1.91%	-9.54%
72702	Weekend	71.46	71.79	2.74%	-0.92%
72702	Weekday	73.75	74.02	2.89%	-0.78%
73101	Weekend	71.96	71.53	2.95%	1.27%
73101	Weekday	74.22	74.09	3.13%	0.42%
81502	Weekday	72.71	72.89	2.37%	-0.43%
81502	Weekend	70.35	73.21	2.05%	-5.87%
90701	Weekday	74.82	73.83	2.67%	2.65%
90701	Weekend	73.01	72.59	2.45%	1.01%
90802	Weekend	70.48	70.66	2.18%	-0.38%
90802	Weekday	72.72	73.07	1.91%	-0.69%
101902	Weekend	72.57	72.41	2.23%	0.34%
101902	Weekday	75.59	75.54	2.64%	0.14%
102701	Weekend	71.96	71.53	2.52%	1.08%
102701	Weekday	74.25	74.09	2.19%	0.36%
110802	Weekend	65.83	64.66	0.61%	0.72%
110802	Weekday	64.77	67.25	0.35%	-0.88%
118401	Weekday	67.75	68.39	0.80%	-0.52%
118401	Weekend	64.39	64.74	0.73%	-0.26%
118403	Weekend	63.90	63.43	0.81%	0.38%
118403	Weekday	65.21	64.50	0.58%	0.41%
128802	Weekday	64.92	66.61	0.51%	-0.86%
128802	Weekend	64.53	63.90	0.84%	0.53%
128803	Weekend	64.35	63.33	0.86%	0.88%
128803	Weekday	64.06	65.91	0.56%	-1.04%
130301	Weekend	71.26	70.54	2.46%	1.76%
130301	Weekday	73.31	73.35	2.71%	-0.10%
133501	Weekday	75.40	74.64	4.50%	3.40%

133501	Weekend	74.51	73.13	4.79%	6.61%
133502	Weekend	72.39	70.55	3.02%	5.56%
133502	Weekday	73.90	73.58	3.22%	1.03%
148501	Weekend	71.55	70.51	1.93%	2.00%
148501	Weekday	73.71	73.71	1.93%	0.01%
149502	Weekday	76.66	77.06	2.82%	-1.14%
149502	Weekend	77.70	75.85	3.16%	5.86%
150002	Weekday	72.06	71.44	2.33%	1.44%
150002	Weekend	73.65	71.37	1.94%	4.44%
154301	Weekday	74.23	73.66	3.15%	1.77%
154301	Weekend	73.18	73.21	2.97%	-0.07%
154901	Weekend	71.45	71.64	2.66%	-0.48%
154901	Weekday	74.06	73.96	2.83%	0.29%
157802	Weekend	64.52	61.46	0.70%	2.15%
157802	Weekday	57.99	61.51	0.22%	-0.76%

e. Since the matching pair data set loading differences are primarily due to voltage reduction, ESTA believes it is acceptable and valid to use Consumers Energy's averaging technique to determine CVR factors.

f. The overall average CVR factor for the CVR feeders computed using Consumers Energy Matching Pair approach compares favorably with the overall average computed using regression analysis. ESTA believes this further confirms the approach. Significant differences in the results for individual feeders is attributable to the small number of data samples.

5.5.2 CVR FACTOR FOR PEAK DEMAND REDUCTION

This section describes the approach used for computing the Peak Demand reduction benefits. This approach is slightly different than the previously described procedure for computing the Energy Waste Reduction benefits.

a) General Requirements

a. Measurement and Verification (M&V) analysis must determine the CVR factor for individual distribution feeders with an accuracy of +/- 5% or better. CVR factor is the percentage change in power or energy attributable to voltage reduction divided by the percentage change in voltage.

b. Separate CVR factors must be provided for Energy Waste reduction and peak demand reduction.

c. Measurement and Verification (M&V) Analysis must separate the electrical impact of voltage reduction on power or energy consumption from other factors that impact power or energy consumption. Other factors include:
   i. Ambient weather conditions and season
   ii. Day of week, time of day

d. CVR voltage and load reductions were calculated by averaging all of the day "CVR On"/"CVR Off" readings and comparing the difference.

e. $$CVR\ factor = \frac{(Avg.\ \text{CVR Off}\ Load - Avg.CVR\ On\ Load)\ /\ Avg.\ \text{CVR Off}\ Load}{(Avg.\ \text{CVR Off}\ Voltage - Avg.CVR\ On\ Voltage)\ /\ Avg.\ \text{CVR Off}\ Voltage}$$

b) ESTA's understanding of the Consumers Energy approach

- The method used by Consumers Energy for computing the CVR factor for peak demand reduction is very similar to the method described above. Consumers Energy assumed the CVR factor obtained above would be the same for peak demand reduction as waste energy reduction. Then the peak demand reduction was calculated as follows:

$$Peak\ Demand\ Reduction = CVR\ Factor\ for\ waste\ energy\ reduction \times Voltage\ Reduction$$

- In 2021, Consumers Energy plans to use "MetrixND", a predictive software tool from ITRON to determine the CVR factor for Peak Shaving reduction. The analysis performed by this software tool is like the regression analysis ESTA used for determining a CVR factor for peak shaving reduction (see next Section). This software determines what the peak load "would have been" during a Peak Demand reduction event if normal voltage had been applied instead of reduced voltage. Consumers Energy plans to use measurements of the following independent variables to perform this analysis:
  - Solar irradiation and hours of sunlight on a given day.
  - Loading on recent past days
  - Dry Bulb temperature

c) Comparison of Consumers Energy approach to best industry practices

- Regression Analysis of Day-On/Day-Off data
  - The CVR M&V approach that is most widely used in the electric utility industry involves multiple regression analysis to determine the relationship between various independent variables that typically impact load (ambient temperature, day of week, voltage level, etc.) and load.
  - The analysis is applied to data collected during CVR Day-On/Day-Off demonstrations like the CVR pilot demonstrations conducted by Consumers Energy.
  - The resulting regression formula is used to estimate what the feeder load "would have been" on a "CVR On" day (reduced voltage) if the voltage had <u>not</u> been reduced.
  - The CVR factor can then be determined by comparing the actual measured loads for CVR On days against the estimated load computed using the regression formula.

- ESTA performed a regression analysis as described above using the day-on/day-off load data and average ambient temperature data supplied by Consumers Energy. The objective of this analysis is to determine what "would have happened" if voltage had not been reduced on the DR day in question.

- This model is trained using data when CVR status is "CVR off". This model uses inputs like voltage, temperature, heating and cooling days and temporal features like hour of the day and season. This model can account for temperature and customer behavior variations and is found to have an average error rate of 3.76%. This trained model is then used on "CVR On" hours of each feeder and demand response day to predict what the load would have been for the hours when CVR was on, if mean voltage instead of reduced voltage was applied. This predicted load is then compared with actual load to compute a mean CVR factor.

- Consumers followed a pre-determined peak reduction schedule as mentioned below:

Table 5-9 Peak Reduction Schedule

DR Date	DR Time Range	Feeder IDs
7/1/2020	1400 - 1500	050403,
7/2/2020	1400 - 1500	072702,
7/8/2020	1400 - 1600	056802, 133502, 154901
7/9/2020	1400 - 1600	090701, 041303, 007303
7/15/2020	1400 - 1700	148501, 081502, 118401, 118403, 017301
7/16/2020	1400 - 1700	128803, 034401, 110802, 157802, 149502
7/22/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502
7/23/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
7/29/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
7/30/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502
8/5/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
8/6/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502

- Regression model is used for each of the feeder on each CVR Date along the time range mentioned in above table to predict load without CVR. Using this a CVR factor is calculated for each instance as follows:

$$CVR\ Factor = \frac{(Avg.\ \text{Predicted}\ Load - Avg.\ CVR\ On\ Load) \Big/ Avg.\ \text{Predicted}\ Load}{(Avg.\ \text{CVR Off}\ Voltage - Avg.\ CVR\ On\ Voltage) \Big/ Avg.\ \text{CVR Off}\ Voltage}$$

Based on this formula an average CVR factor of 1.51 is computed for all feeders on all Demand response days. As mentioned above average error rate of regression model was 3.86% so ESTA can claim that CVR factor should lie with $\pm$3.86% of 1.51 or between 1.45 and 1.56.

- The results of this analysis were compared with Peak Demand Reduction CVR factor computed by ESTA for another electric utility (utility name confidential). As seen in Figure 5-4, the Peak demand was reduced 600kW (6.5%) during a 4-hour, 15-minute voltage reduction of 4.5%. The Peak Demand CVR factor for this utility was 1.45 (6.5% / 4.5%). This is consistent with the results obtained by ESTA for Consumers Energy.

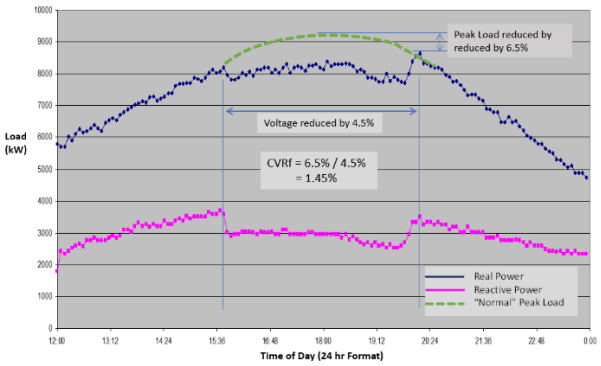


Figure 5-4 Results of Peak Demand CVR

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. ESTA has reviewed the Consumers Energy "Peak Demand Reduction" M&V method and offers the following comments and conclusions.

b. An average CVR factor of 1.51 is computed for all feeders on all Demand response days. As mentioned above average error rate of regression model was +/- 3.89% so that the CVR factor should lie with of 1.51 or between 1.45 and 1.57

c. Table 5-10 below shows the average Peak demand CVR factor that ESTA computed for each Consumers Energy feeder on all demand response days.

Table 5-10 Peak Demand CVR factors for Individual feeders

Feeder ID	Model Error Rate	CVR Factor
7303	4.10%	1
34401	4.26%	3.73
41303	2.95%	0.65
43502	3.29%	0.69
50403	3.82%	1.61
56802	2.12%	1.32
72702	3.45%	1.91
81502	5.94%	0.33
90701	4.39%	1.11
110802	3.59%	1.71
118401	3.03%	1.45
118403	3.93%	0.89
128803	3.26%	1.35
133502	4.37%	1.31
148501	3.85%	2.92
149502	4.33%	2.54
150002	5.33%	2.5
154901	3.48%	1.07
157802	4.39%	0.6
Average	**3.89%**	**1.51**

d. Figure 5-5 below shows the average effect of peak demand reduction for all feeders.

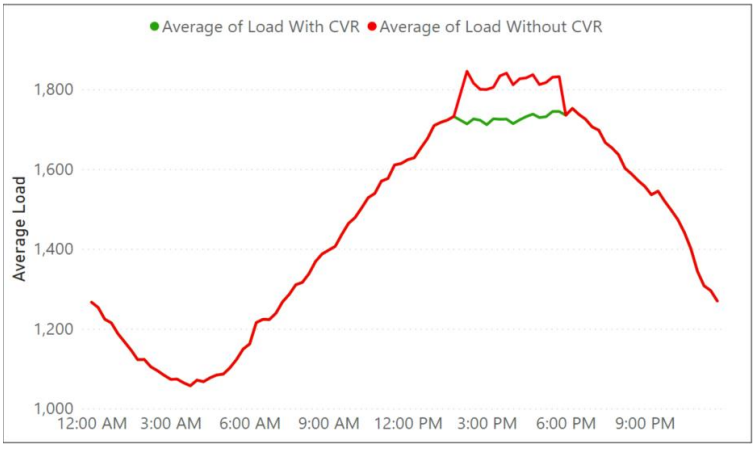


Figure 5-5 Average Peak Demand CVR Factor For Consumers Energy

6 SUMMARY OF FINDINGS CONCLUSIONS AND RECOMMENDATIONS

Following is a summary of ESTA's major findings, conclusions, and recommendations resulting from this assessment:

- **Feeder Selection:** As stated earlier in this report, the approach used by Consumers Energy to select feeders for its CVR Demonstration project far exceeds the feeder selection approach used by many other utility companies (based on ESTA experience).
    - Key characteristics of the CVR demonstration feeders selected by Consumers Energy match the characteristics of the broader set of "CVR Proposed" feeders on which CVR may be implemented in the future. While some characteristics are not the same, customer mix is very similar between the two groups. ESTA considers this to be one of the most important factors that determines the CVR factor for a given feeder.
    - As a result, ESTA believes that the selected CVR feeders represent the broader community of Consumers Energy feeders on which CVR is likely to be implemented.
    - In ESTA's opinion, it is acceptable to assume that the results obtained for the initial 50 feeders can be applied to future CVR feeders selected from the CVR Proposed feeder set.
- **CVR Solution:** The Consumers Energy CVR solution is a DSCADA rules-based solution, meaning a set of predetermined rules involving the application of Boolean logic to measurements acquired by the distribution SCADA system.
    - Most of the CVR solutions that have been successfully implemented by North American electric distribution systems are rules-based systems like what has been implemented by Consumers Energy. While this approach has some limitations, such as inability to adapt automatically to feeder reconfiguration, the approach has the benefit of simplicity, ease of operating and maintenance, and cost effectiveness, while providing the expected benefits.
    - Shortcomings of the existing approach include:
        - Lack of immediate voltage feedback to alert system operators to low or high voltage conditions on the feeder. Currently, such events may be detected the next day through manual review of voltage records from AMI. This approach is generally acceptable if major voltage deviations (e.g., voltage dips well below lower ANSI C84.1 limit) do not routinely occur.
        - Inability to adapt automatically to changing feeder configuration. Currently, Consumers Energy disables CVR if the feeder is reconfigured. While not the preferred approach, disabling CVR is acceptable if this is for a short duration (i.e., normal feeder configuration restored as quickly as possible),

- In the future, Consumers Energy should consider implementing model-driven VVO on its new ADMS. This should eliminate the shortcomings listed above.

- **Controlled Devices**

  - Consumers Energy controls switched capacitor banks and voltage regulators on its feeders. Within the industry, this is the most common complement of controlled equipment.

  - In the future, additional control requirements may apply. Examples include smart inverters and distributed generators. If these new requirements emerge at Consumers Energy, and ADMS-based, model-driven solution may be required due to the impracticality of handling these requirements with fixed Boolean logic.

- **Measurement data**

  - The measurements and equipment status information acquired by Consumers Energy for CVR purposes is adequate for meeting the basic needs of this application.

  - Some "scrubbing" was needed to eliminate questionable data (such as "stale" data measurements) collected during the CVR demonstration project. However, it is noted that data scrubbing is typically required on all M&V projects of this type, and that the amount of data scrubbing for Consumers Energy was far less than other M&V projects done by ESTA.

  - Adding near-real-time voltage measurements or low/high voltage alarms from AMI or bellwether meters would be beneficial, especially for heavily loaded feeders that are routinely operated close to the industry limits. Adding voltage feedback will enable Consumers Energy to gain additional benefits by operating with small margins (closer to voltage limits).

- **Approach to Measurement and Verification and Results Obtained**

  - The Matching Pairs M&V approach is relatively easy to understand and implement, compared to other advanced techniques (such as regression analysis and neural network modelling). As a result, it is possible to cross check the results using simple averaging to confirm the results. Another advantage is the ability to gain acceptance of the results by decision makers who do not have an advanced mathematical and statistical background.

  - ESTA performed an M&V analysis on the Consumers Energy data using multiple regression analysis that included consideration of loading, voltage, and ambient temperature. Regression analysis is the most widely used approach in the electric utility industry for CVR M&V.

  - The overall average CVR factor for the CVR feeders computed using Consumers Energy Matching Pair approach is 0.82, which compares favorably with the overall average computed using

regression analysis (0.77 +/- 3.7%). We believe this further confirms the approach. Significant differences in the results for individual feeders is attributable to the small number of data samples.

- ESTA concludes that the results obtained by Consumers Energy during its CVR demonstration and analysis are valid and representative of results than can be received by implementing CVR on the CVR Proposed data set.

- ESTA computed a CVR factor for Peak Demand reduction using regression analysis to determine what "would have happened" during peak load conditions if normal voltage were applied on Demand Response days when CVR Peak Demand reduction occurred. The result of this analysis was a Peak Demand Reduction CVR factor of 1.56 +/- 3.86% on average for the 20 feeders on which Peak Reduction CVR was applied.

- Consumers Energy has assumed that the CVR factor for Peak Demand reduction is the same (0.82) as the CVR Factor for Waste Energy Reduction, which is a very conservative assumption compared to the results computed by ESTA. Based on the results of ESTA's Peak demand CVR analysis and the results at one other electric utility (undisclosed), the results are considerably higher than the CVR factor for peak demand reduction assumed by Consumers Energy. The main reason for this difference is that the complement of equipment and appliances running during daily peak load hours is considerably different than the equipment complement running on average. For example, the amount of air conditioning load during peak load hours on a hot summer day is likely to be significantly higher than the average AC load for the day.

In 2021, Consumers Energy plans to use "MetrixND", a predictive software tool from ITRON to determine the CVR factor for Peak Shaving reduction. The analysis performed by this software tool is like the regression analysis ESTA used for determining a CVR factor for peak shaving reduction. In ESTA's opinion, this approach will yield much more accurate results for the Peak Demand CVR factor than the current conservative approach. ESTA strongly recommends that Consumers Energy use this approach for future analysis of peak demand CVR reduction.

Appendix A CVR BACKGROUND INFORMATION

A.1 VOLTAGE REDUCTION

As electric utilities seek to address energy efficiency and conservation portfolios, many electric distribution utilities are turning to voltage reduction to satisfy energy efficiency, demand reduction, and energy conservation objectives. Voltage reduction involves operating the distribution feeder at a voltage that is in the lower portion of the acceptable voltage range (See Figure 6-1). Electric utility experience, backed by extensive laboratory testing, has shown that many electrical loads, especially electric motors, consume less real and reactive power and perform just as well (or better) when voltage is lowered slightly. When voltage reduction is performed whenever possible (up to 24 hours per day, seven days per week), this is called "Conservation Voltage Reduction". This is because 24-hour-per-day operation is primarily intended to promote energy conservation. If voltage reduction is used only during peak load periods for purposes of peak shaving, the term voltage reduction (VR) or voltage optimization is commonly used.

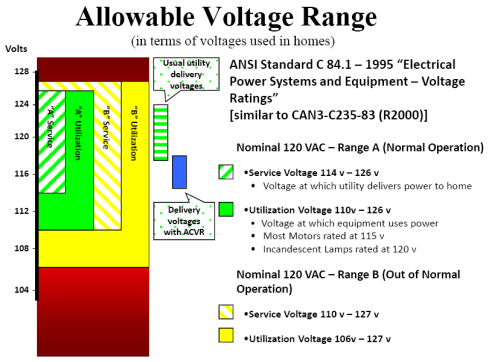


Figure 6-1 Allowable Voltage Range (per ANSI C84.1)

Many electric utilities and their associated grid management authority have used voltage reduction as a means of reducing power quickly during a peak load emergency. In the past, such voltage reductions were referred to as "brown-outs" due to the dimming effect voltage reduction may have on incandescent light bulbs. For the most part the term no longer applies as the newer generation of compact fluorescent lamps remains bright as voltage is reduced by up to five percent. Numerous utilities are planning to operate with reduced voltage on a continuous basis (for energy conservation) or during peak load periods (for demand reduction).

To implement CVR effectively with no adverse impact on consumer electrical loads, it is often necessary to implement distribution infrastructure improvements to "flatten" the voltage profile along the feeder. This allows more voltage reduction without violating minimum voltage constraints. Figure 6-2 illustrates the use of switched capacitor banks to "flatten" the voltage profile, followed by voltage reduction. The green line in this Figure 6-2 represents the starting voltage profile at one point in time along the feeder. The red line shows the impact of voltage "flattening". In this cases the effect was achieved by switching on the three switched capacitor banks that are installed on the feeder. The brown line in Figure 6-2, shows the effect of voltage reduction on the "flattened" voltage profile. As seen in Figure 6-2, the voltage level at the end of the feeder that is furthest from the substation changes very little from the starting point. However, the voltage at all other points along the feeder are reduced considerably. This illustrates the benefit of voltage conditioning.

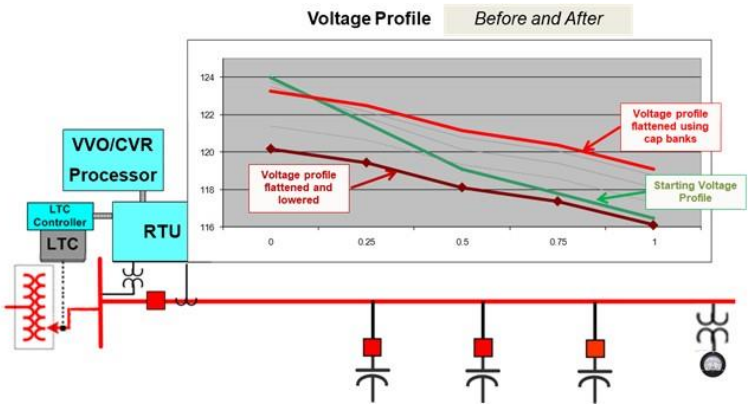


Figure 6-2- "Flattening" And "Lowering" The Voltage Profile

Many electric utilities view VR as a very attractive measure for efficiency improvement, because, in most cases, significant benefits can be achieved for a minimal investment and with no customer sacrifices. Because VR can usually be implemented without making major investments in equipment and infrastructure improvements, benefits can be achieved in the shortest possible time.

The specific benefits that can be achieved vary based on customer type (residential, commercial, industrial, etc.), time of day, day of week and season, climate zone, and other such factors. The amount of benefit is also affected by the degree to which voltage can be reduced. Feeders whose minimum voltage is near the bottom of the acceptable range will provide little or no CVR benefits, while feeders with higher distribution voltage often gain the most from CVR.

CVR benefits will be affected by new "up and coming" appliances that comprise a growing percentage of the load. Many new appliances will be equipped with electronic controls that improve the nominal efficiency of the device. Many of these controls exhibit "constant power" behavior which is not favorable for achieving CVR benefits. With constant power loads, the electricity consumed by the device stays constant as voltage is reduced. However, as the voltage is reduced, current increases which can produce higher electrical (I^2R) losses on the feeder. Due to the critical nature of the application (e.g., system emergency voltage reduction), it is important to be able to predict the outcome of voltage reduction.

A.2 SCADA "RULES-BASED" APPROACH

Consumers Energy uses one of the most common approaches to CVR: the SCADA "rules based" approach. This approach is depicted in Figure 6-3. This approach determines what volt-VAR control actions to take by applying a predetermined set of logical "rules" to a set of real time measurements from the associated substation and feeder. An example rule is: "If the voltage measured at point "X" is less than 120 volts AND the reactive power flow measured at the substation end of the feeder is greater that 900kVAR (lagging), then switch capacitor bank "1" to the ON position". These rules are determined in advance by the distribution engineers and operators using power flow analysis or general knowledge about the historical operation of the feeder.

The SCADA rules-based approach relies on intelligent controllers for interfacing with the switched capacitor banks and voltage regulators. The SCADA rules-based approach uses the Consumers Energy Distribution Supervisory

Control and Data Acquisition (DSCADA) system to interface with the field devices and intelligent controllers. The communication facilities enable the system to base its control actions on overall feeder conditions rather than just on local conditions at the site of the capacitor bank or voltage regulator. The communication facilities also enable Consumers Energy to monitor the operating status of the voltage regulators and switched capacitor banks so that appropriate actions can be taken immediately when a component failure occurs.

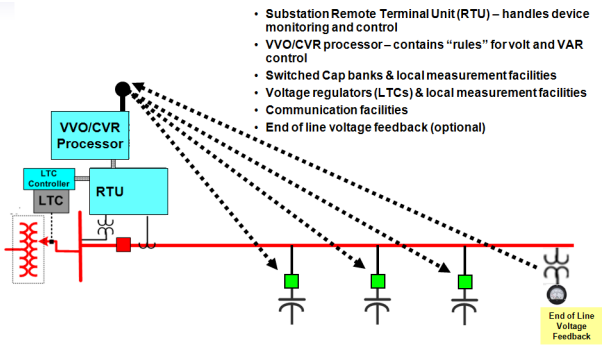


Figure 6-3 SCADA Rules Based Approach

This approach works well for the operating environment that exists on many electric utility distribution feeders today (e.g. minimal DG, infrequent changes in feeder configuration). However, in the future as the penetration of large DG units grows and advanced distribution applications (such as Fault Location Isolation and Service Restoration (FLISR)) become prevalent, the rules-based approach may lack the flexibility to address all future operating possibilities. In such cases, a more sophisticated "model-driven solution" may be needed.

A.3 CVR FACTOR EXPLAINED

CVR factor reduction (also known as load-voltage sensitivity) is an industry standard metric for identifying the effectiveness of voltage on the electric distribution system. CVR factor is given by the following formula:

CVR factor = (% change in kWh energy consumption) / (% change in voltage)

As explained in following sections, the load-voltage sensitivity of a particular electrical device depends on the electrical characteristics of the individual device which can be determined through laboratory testing. The load-voltage sensitivity or CVR factor of an entire customer premise, an entire feeder, an entire substation, or other entity containing more than one appliance, depends on the aggregate load-voltage sensitivities of the individual appliances in the entity.

A.4 LOAD-VOLTAGE SENSITIVITY OF INDIVIDUAL DEVICES

Most electrical appliances consume less electric power when voltage is reduced. The relationship between voltage and electric power for an appliance is given by the "ZIP" model of the appliance, which is a combination of the following components:

- **Constant Impedance Component (Z)** – When voltage (V) applied to a constant impedance device is reduced, the current (I in amperes) drawn by the device decreases by the same amount to keep the impedance ratio (V / I) constant. So, when voltage is reduced, the consumed power (V x I) is lowered by a significant amount. Electric heating elements in water heaters and electric stoves are examples of loads that primarily have constant impedance behavior. Incandescent light bulbs, which are becoming a thing of the past, also exhibit constant impedance behavior. Figure 6-4 below contains a graph showing test results obtained when voltage applied to an incandescent light bulb was varied. The load-voltage sensitivity is the slope of this line, which is approximately 1.6, meaning that if voltage applied to the device is reduced by 1.0%, the power consumed would be 1.6%.

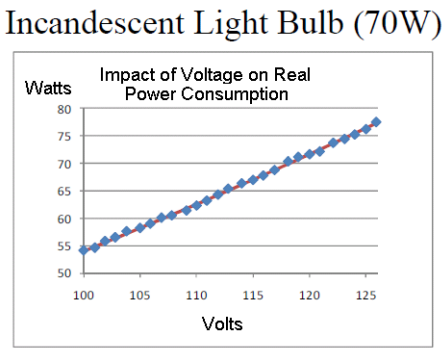


Figure 6-4 Load—Voltage Sensitivity Test Results for Light bulb

- **Constant Current Component (I)** – Constant current loads draw power in proportion to the applied voltage. That is, P= I x V, where current I is held constant. So, the power drawn by constant current loads will be lowered when voltage is reduced, but not as much as constant impedance devices. There are relatively few constant current devices that exhibit constant current behavior. Examples include welding units, smelting equipment, and electroplating processes. However, some electric vehicle chargers may exhibit constant current behavior. Normally, and EV charger exhibits a constant power behavior in which current increased as voltage is reduced to maintain a fixed power draw by the charger. However, when current reaches a maximum amount when current reaches a maximum allowable amount, the current drawn remains fixed and is clamped at the maximum as further voltage reduction occurs.

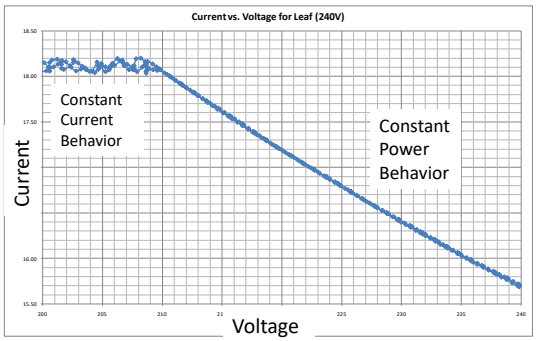


Figure 6-5 Load-Voltage Characteristic of EV Charger

- **Constant Power Component (P)** – Constant power loads draw the same amount of power regardless of the applied voltage. So, the CVR factor for constant power loads is zero. Computer power supplies are constant power devices as are many modern devices that used switched power supplies. Electric motors are often considered to be constant power devices. However, tests have shown that for small voltage reductions (a few percent), motors exhibit constant impedance behavior. Load-Voltage sensitivity for a computer power supply is shown in Figure 6-6 below.

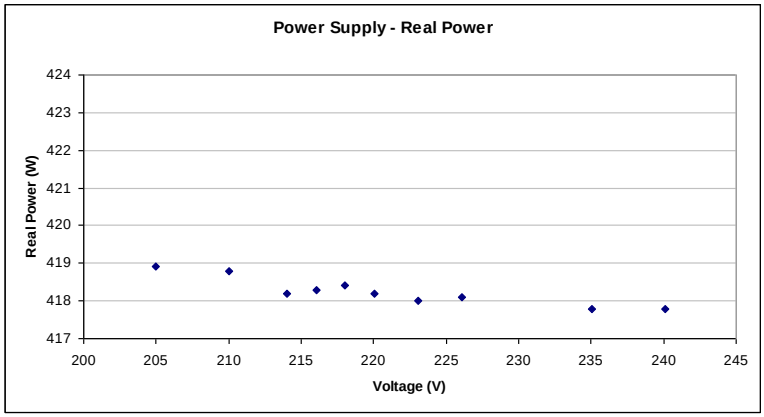


Figure 6-6 Constant Power Behavior of Computer power Supply

Commonly used electrical appliances usually exhibit individual CVR factors that are a combination of the ZIP component characteristics. Figure 6-7 below shows CVR factors for various types of electrical appliances.

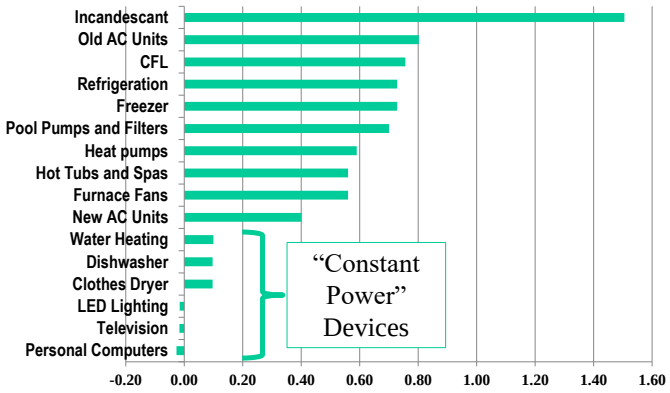


Figure 6-7 CVR Factors for Common AC Appliances

A.5 LOAD-VOLTAGE SENSITIVITY AT THE PREMISE AND FEEDER LEVEL

The power supplied to a single residential or commercial entity is the sum of the power consumed by all the individual electrical appliances within the entity. The Load-Voltage sensitivity or CVR factor for the single entity is the sum of the CVR factors for the individual types of appliances weighted by the percentage of load consumed by each appliance. Figure 6-8 and Figure 6-9 below show how the aggregate load-voltage sensitivity differs for a typical single-family residence and a commercial office building. For these examples, power consumed by each type of appliance has been obtained from RECS and CBECS data published by the US Department of Energy (DOE) for premises located in the "mixed-humid" climate zone. The energy consumed by individual appliances, and the premise CVR factor, would be different in other climate zones.

Year	State	Climate	Customer Class			
2021	New York	MIXED-HUMID	Single-Family			
SAMPLE SIZE:	60					
		Average kWh				
Enduse	Summer	Winter	Shoulder	Total kWh	LTV Factor	KWh x LTV
Clothes Dryer	91	137	160	388	0.8	310.48
Cooking	109	88	145	342	0.3	102.47
Cooling	1,305	0	278	1,583	0.5	791.38
Dishwasher	27	41	48	117	0.5	58.304
Freezer	86	69	115	270	0.3	80.977
Furnace Fans	108	40	54	202	1.23	248.02
Heating	0	131	45	176	0.1	17.552
Lighting (Incand)	100	131	158	389	1.536	597.21
Lighting (CFL)	62	81	98	242	0.748	181.08
Lighting (LED)	26	35	42	103	0.976	100.24
Other	1,428	1,144	1,901	4,473	1	4473
Hot Tubs and Spas	15	13	20	48	1	47.663
Pool Pumps and Filters	143	115	191	449	1.23	552.43
Personal Computers	136	179	215	530	0.1	53.04
Refrigeration	449	360	598	1,407	0.3	422.23
Television	437	352	582	1,371	0.1	137.11
Water Heating	0	0	0	0	0.1	0
	4,524	2,914	4,650	12,088	Aggregate LTV	0.6761

Figure 6-8 CVR Factor for a typical Single Family Residence

Year	State	Climate	Customer Class			
2021	New York	MIXED-HUMID	Office			
SAMPLE SIZE:	82					
	Average kWh (Total End Use Energy / Total Number of Premises)					
Enduse	Summer	Winter	Shoulder	Total kWh	LTV Factor	KWh x LTV
Computer Use	29,402	38,671	48,579	116,653	0.1	11665.3
Cooking	119	157	197	472	0.3	141.7
Cooling	41,113	0	10,261	51,375	0.5	25687.3
Heating	50	12,627	4,941	17,618	0.2	3523.7
Lighting	62,108	81,685	102,613	246,407	0.748	184312.3
Miscellaneous Use	24,692	32,476	40,796	97,964	1	97964.0
Office Equipment	15,026	19,761	24,824	59,611	0.2	11922.1
Refrigeration	4,507	5,928	7,448	17,884	0.4	7153.5
Ventilation	14,992	19,718	24,769	59,479	0.7	41635.6
Water Heating	1,166	1,533	1,927	4,626	0.1	462.6
	193,177	212,556	266,356	672,088	Aggregate LTV	0.57205

Figure 6-9 CVR Factor for a Typical Office building

Similarly, the CVR factor for an entire feeder or substation is the weighted sum of the CVR factors for the individual customers connected to the feeder or substation. In this case, the weighting factor is the percentage of total feeder power consumed by each entity.

It can be concluded that the load-voltage sensitivity depends only on the types of appliances and equipment served and the portion of energy consumed by each type of appliance. In other words, two entities (premises, feeders,

substations, etc.) that supply the same types of appliances and energy consumption per appliance will have the same CVR factor.

As explained above, aggregate load-voltage sensitivity depends on appliance type and climate zone. If all Consumers Energy substations and feeders are in the same mixed-humid climate zone, then CVR factor varies only by the customer mix (e.g., residential, commercial, industrial) served by the feeder or substation.

A.6 CVR "BENEFITS" FOR DIFFERENT TYPES OF FEEDERS

While the load-voltage sensitivity is nearly the same for a given set of appliances in a given climate zone, the energy conservation benefits (kWh reduction) for a given feeder or substation will depend on the following items:

- The amount of voltage reduction that is possible without violating voltage limits. A larger voltage reduction will result in larger kWh savings. The possible voltage reduction on short, lightly loaded feeders is usually greater than the possible voltage reduction on longer, heavily loaded feeders (which may be voltage-limited). For example, reducing the voltage by 2% on a 1.0 MWh load with a 0.7 CVR factor will reduced the consumed energy by 1.4%; if voltage can only be reduced by 1%, then kWh savings would be half that amount.

- The total energy consumption by the entity. A one percent voltage reduction on a heavily loaded entity will produce a greater kWh reduction than a lightly loaded entity. For example, reducing the voltage by 2% on a 1.0 MWh load with a 0.7 CVR factor will reduced the consumed energy by 1.4% of 1.0 MWh; a 2% voltage reduction on a 2.0 MWh load would save 1.4% of 2.0 MWh (twice the benefit).

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
Exhibit No.: A-169 (JMP-4)
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Witness: JMPartlan
Date: June 2025

Line		2023	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT COTTAGE GROVE PREVO LCP 259	4,209	2	5	0	1	0
2	RPOUT17 PINCONNING_PINCONNING LCP 693	12,590	0	0	0	1	0
3	RLBY ASHMAN-ASHMAN, LCP 765	71,373	1	0	0	0	0
4	RPOUT BUSCH ROAD/CANADA LCP 734	7,463	2	6	3	0	2
5	RPOUT ST CHARLES_SAGINAW LCP 652	134	0	1	0	1	0
6	RPOUT APPLETON-PERRY LCP 957 OVERLOAD	11,240	0	0	0	1	0
7	RPOUT Remus-Mecosta* LCP 126 Overload	37,518	4	1	2	9	1
8	RPOUT Ensley-Distribution LCP 707	26,845	2	2	0	1	0
9	RPOUT Ohman Road-Sears LCP 736*	59,669	0	0	1	1	1
10	RPOUT Ohman Road-Sears* LCP 002	116,708	6	2	2	1	0
11	RPOUT Rodney-Rodney LCP 310 - OHL	9,312	6	5	0	1	1
12	RPOUT Rodney-Horsehead Lake LCP 241*	15,445	2	2	1	1	0
13	RPOUT Rodney-Rodney LCP 310 - UGL	5,564	6	5	0	1	1
14	RPOUT Foreman Vergennes LCP 572	80,560	2	3	1	2	0
15	RPOUT CALEDONIA-92ND STREET email	22,854	0	1	1	0	0
16	RPOUT Alto McCords 60th St SE	7,738	1	0	2	1	0
17	RPOUT DUTTON DUTTON LCP 228	105,115	0	1	0	1	0
18	RPOUT Calvin Woodcliff LCP 144-ZLD HDQ	65,531	0	1	0	1	0
19	RPOUT Orleans Orleans 091 PREBUILT	1,738	3	1	0	2	0
20	RPOUT HARVARD LAKE/HARVARD LAKE SUB #1	72,196	0	1	0	1	0
21	RPOUT HARVARD LAKE/HARVARD LAKE SUB #2	64,582	0	1	0	1	0
22	RPOUT CARSON CITY/HARVEST LCP 420*	16,158	4	2	3	1	0
23	RPOUT Godfrey LCP 545	10,295	3	1	2	0	0
24	RPOUT Hubbardston LCP 325	23,997	3	1	0	1	1
25	RPOUT ORLEANS LONG LAKE LCP 147	21,457	4	1	0	0	1
26	RPOUT ORLEANS LONG LAKE LCP 169	14,897	5	1	1	0	1
27	RPOUT Orleans_Long Lake LCP 030 OL	12,196	0	2	3	0	3
28	RPOUT CARSON CITY_BUTTERNUT LCP 0002*	25,087	0	0	0	4	1
29	RPOUT CRYSTAL_CRYSTAL ROAD LCP 554	31,078	6	1	3	1	0
30	RPOUT KENT CITY/TYRONE LCP-510	3,210	3	0	2	3	1
31	RPOUT KENT CITY_CASNOVIA LCP-869	18,673	4	0	0	2	0
32	RPOUT PLAINFIELD/KUTTSHILL* LCP-051	98,904	0	2	2	3	0
33	RPOUT COWAN LAKE_RAMSDELL* LCP-657	15,823	0	0	1	0	1
34	RPOUT Cedar Springs-Edgerton LCP 705	18,191	5	4	4	1	1
35	RPOUT Kent City_Casnovia* First Zone Fus	9,226	1	1	1	5	1
36	RPOUT Pierson-Pierson* LCP 605	3,617	3	1	1	0	0
37	RPOUT RATIGAN_GREELEY* LCP-002	17,616	2	1	2	0	0
38	RPOUT LINDEN N LINDEN LCP 720	588	0	0	0	1	0
39	RPOUT Clio/Pine Run LCP 771	2,083	0	0	1	0	0
40	RPOUT Mayfair/Home TLM 0856264411 CPLT	82,752	0	0	1	0	0
41	RPOUT Mayfair/Home TLM Edwards Ave	159	5	2	3	0	0
42	RPOUT Mayfair/Home Edwards Ave	114	5	2	3	0	0
43	RPOUT Mayfair/Home TLM Dupont St	171	5	2	3	0	0
44	RPOUT MT MORRIS/NEFF TLM 0856121103 CPLT	73,277	4	5	2	0	1
45	RPOUT Otisville/Irish Rd LCP 59	4,445	2	0	1	0	1
46	RPOUT MAYFAIR HOME TLM 0856264404	39,442	5	2	3	0	0
47	RPOUT STANLEY NORTHLAND TLM 0856241204	31,002	3	3	1	2	0
48	RPOUT Field Rd/Parker Crk TLM0956191101	22,590	8	0	1	0	0
49	RPOUT Mayfair/Home TLM 0856264404 5605 B	130	5	2	3	0	0
50	RPOUT Mayfair/Home TLM 0856264404 5518 G	153	5	2	3	0	0
51	RPOUT MAYFAIR/MAYFAIR TLM 0856342103	98,075	0	2	0	3	0
52	RPOUT MAYFAIR/MAYFAIR - OHS 3509 MINERVA	154	4	2	2	3	0
53	RPOUT MAYFAIR/MAYFAIR- OHS 3302 WINDLAND	170	4	2	2	3	0
54	RPOUT IRISH ROAD_CRYSTALWOOD LCP 196	2,032	3	5	0	2	0
55	RPOUT SPRING DRIVE FERRIS - LCP 380	23,809	3	3	2	0	1
56	RPOUT_Manistee_Lake Michigan	7,440	0	0	0	0	0
57	RPOUT ORIOLE HAMLIN LCP 0728 - OHL	27,703	2	1	2	1	0
58	RPOUT ORIOLE HAMLIN LCP 0728 - UGL	127,004	2	1	2	1	0
59	RPOUT AGNEW ROBINSON	12,064	1	0	1	1	0
60	RPOUT NORGE MACHINE EDGEWATER RECL	121,252	2	1	0	2	0
61	RPOUT NUNICA_WILSON SUB	13,699	3	1	2	2	0

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Line		2023	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT EVANSTON EVANSTON LCP 564	4,970	1	2	3	4	0
2	RPOUT18 GLADWIN/GLADWIN LCP825 LOC 13-28	15,313	2	0	0	1	4
3	RPOUT18 GLADWIN/GLADWIN LCP 825 LOC 1-12	128,202	2	0	0	1	4
4	RPOUT22 OBERLIN BENMARK LCP 604	9,406	3	5	4	4	2
5	RPOUT22 GLADWIN BUZZELL LCP 310 CMPLT	8,904	5	2	3	2	0
6	RPOUT LCP 866 SMALLWOOD DIST	41,803	3	0	0	1	0
7	RPOUT22 BEAVERTON ROSS ST LCP 504 COMPLT	8,056	6	5	1	0	1
8	RPOUT NOBLE_DUBY LCP 7299	45,857	6	0	0	4	0
9	RPOUT BACKUS-SPRINGBROOK COORD	20,318	2	1	1	1	1
10	RPOUT Duquite_Saganing LCP 960	9,841	5	4	1	2	1
11	SYSP BESSINGER_QUARRY LCP 423 - 2 crews	29,721	0	0	0	0	0
12	RPout Pellston_Burtlake LCP 283	25,126	9	1	0	1	1
13	RPOUT LAKE CITY-STITTSVILLE COORD	5,458	0	0	0	1	0
14	RPOUT Hospital/Kids Creek LCP 740	79,626	4	3	1	0	0
15	RPOUT Hospital/Kids Creek LCP 740 UGL	97,229	4	3	1	0	0
16	ON HOLD -- RPOUT Bedford - Meachem LCP 7	1,715	4	0	0	3	0
17	RPOUT Alder Creek - E Leroy LCP 529	2,945	5	0	1	2	0
18	RPOUT Elm St-Verona LCP 281 (SECTRPL)*CE	142,293	1	1	0	1	0
19	RPOUT Elm St-Verona LCP 353(SECTRPL)*CE	40,021	2	1	4	2	0
20	RPOUT - Convis Convis various lcps	7,875	1	1	2	1	0
21	*RPOUT - 15 Mile A Drive 773*CE CREWS	6,462	0	1	1	2	1
22	RPOUT Athens - Sherwood	86,925	1	5	0	0	1
23	RPOUT DELTON_DELTON LCP 087	36,467	1	5	2	1	0
24	RPOUT22 RIX ROAD_UNDERPASS	15,356	2	0	1	2	0
25	RPOUT ATWATER-CRONK	11,295	3	0	1	1	0
26	RPOUT GLENDALE_HERCULES	16,520	2	0	2	1	0
27	RPOUT PICKEREL_EAST LAKE LCP 223	39,550	4	0	0	2	0
28	RPOUT17 PORTAGE/CARPENTERS CORNERS	26,586	0	0	0	1	0
29	RPOUT ALAMO-PINE GROVE LCP 638	41,314	0	4	2	3	1
30	RPOUT ALAMO_PINE GROVE LCP 5193	71,883	0	7	3	1	0
31	RPOUT GALESBURG_CHARLESTON LCP 574 *401	81,603	0	5	0	1	1
32	RPOUT PICKEREL_EAST LAKE LCP 223 - UG	21,023	4	0	0	2	0
33	RPOUT 25 1_2 Mile Rd	859	1	0	1	2	0
34	RPOUT READING_CAMBRIA	11,493	2	0	1	0	0
35	B2LN5021 RPOUT21 CENTREVILLE_BUSINESS LC	2,311	1	2	5	0	0
36	CEMI11 CARLETON ROAD_BECK ROAD	172,546	3	2	1	2	0
37	RPOUT-DOBSON RD HALF MOON 354	3,356	0	1	1	1	1
38	RPOUT21 CENTREVILLE_INDUSTRIAL LCP 502	90,314	2	0	2	0	0
39	RPOUT READING_CAMBRIA LCP 649	12,392	1	3	1	2	0
40	LNDC RPOUT CEMI12 QUINCY_QUINCY OHL	1,000	2	1	1	0	0
41	RPOUT CEMI12 QUINCY_QUINCY LCP 769	40,388	2	1	1	0	0
42	RPOUT CEMI12 QUINCY_QUINCY LCP 769 UGL	11,813	2	1	1	0	0
43	RPOUT Breton Towers LCP 687 ZLD HQ	50,491	0	0	1	0	0
44	RPOUT22 Ramona/Robinson New Recloser	75,235	0	1	1	2	0
45	RPOUT FILLMORE-N BLENDON 602	13,677	3	0	3	1	0
46	RPOUT Breton Towers Sub	32,777	5	0	1	1	0
47	RPOUT FILLMORE_64TH STREET LCP SUB	11,998	3	1	0	0	0
48	SYSP OTTAWA BEACH-LAKEWOOD	946	0	1	0	10	0
49	RPOUT LCP 538 OTTAWA BEACH-LAKEWOOD OHL	5,249	3	3	1	0	0
50	RPOUT CASCO_BLUFF LCPS SUB 385 394 226 (	7,899	2	0	1	0	0
51	RPOUT MACATAWA WENDT PARK LCP 617 *carde	42,551	1	0	1	0	0
52	RPOUT BENTHEIM_140TH AVENUE LCP 306 OHL	153,891	0	0	0	1	0
53	RPOUT BLACK RIVER FILLMORE LCP 459	1,955	1	1	0	2	0
54	RPOUT BELKNAP-TODD FARM SYSP2021	1,157	2	2	2	0	0
55	RPOUT VIRGINIA PARK_CASTLE BEELINE RD *s	36,375	8	4	4	3	0
56	RPOUT MILL GROVE_ALLEGAN HYDRO LCP 378	1,362	3	5	5	1	0
57	RPOUT MILL GROVE_ALLEGAN HYD	101,845	3	5	5	1	0
58	RPOUT MERSON DUCK LAKE LCP 961	49,082	3	1	5	2	0
59	RPOUT LCP 538 OTTAWA BEACH-LAKEWOOD UGL	74,710	3	3	1	0	0

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
Exhibit No.: A-169 (JMP-4)
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Witness: JMPartlan
Date: June 2025

Line		2024	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT17 ITHACA/FAIR GROUNDS LCP 313	47,942	2	1	3	3	0
2	RPOUT17 ITHACA/FAIR GROUNDS LCP 331	25,717	0	0	0	1	0
3	RPOUT COTTAGE GROVE PREVO LCP 259	10,077	2	5	0	1	0
4	RPOUT COGGINS_NEWBERG LCP 082	26,530	0	5	0	2	0
5	SYSP COTTAGE GROVE PREVO LCP 866	53,439	6	1	0	2	0
6	SYSP MT FOREST BENTLEY 746 REACH	30,125	2	2	1	5	0
7	SYSP KAWKAWLIN RUSSELL 786	24,578	4	1	1	3	0
8	RPOUT LETTS ROAD_MONROE LCP 212	3,593	7	1	2	7	0
9	SYSP19 Bradford_Distribution LCP 057	6,880	1	1	0	2	0
10	SYSP19 Waldo Jefferson SUB	35,270	0	0	2	1	0
11	SYSP19 Price Road_Price LCP 424	14,571	1	0	0	2	0
12	SYSP19 Letts Road_Walker LCP 771	27,150	5	2	0	2	0
13	RPOUT ST CHARLES_SAGINAW LCP 652	6,551	0	1	0	1	0
14	RPOUT BELL ROAD/ALBEE LCP 922	15,196	0	1	3	1	1
15	RPOUT24 Hemlock Nelson LCP585	38,268	2	3	1	1	0
16	RPOUT OHMAN ROAD_SEARS LCP 809	15,968	0	4	0	0	1
17	RPOUT TAMARACK_AMBLE LCP 521	19,236	5	5	7	1	0
18	RPOUT_ENSLEY_BAPTIST LAKE_LCP 754	351	1	0	2	0	2
19	RPOUT CONKLIN PARK_HOLLY LCP 857	4,945	1	0	4	0	0
20	RPOUT Broadmoor Airwest LCP 544 OHL	16,080	2	0	0	0	0
21	RPOUT Thornapple Headley LCP 435	41,588	1	4	3	0	0
22	RPOUT FULTON_RIPPLING LCP 740	15,350	0	2	2	3	0
23	RPOUT KENTWOOD_PRINCETON LCP 0639	56,916	1	0	2	1	1
24	RPOUT BROADMOOR_MEADOWLANE LCP 0262	76,949	0	2	1	1	0
25	RPOUT22 Godfrey_Lowell	68,415	0	0	0	1	0
26	RPOUT Easton_Haynor LCP 380	17,427	3	2	2	3	1
27	RPOUT EASTON_PARMETER LCP 844	127,246	4	1	2	0	0
28	RPOUT Saranac_Centerline LCP 196**	16,487	0	0	1	2	0
29	RPOUT PECK ROAD_M-91 LCP 428	7,904	0	0	0	0	1
30	RPOUT PEACH RIDGE/BALLARD SUB REACH ISSU	3,475	2	1	0	0	0
31	RPOUT** Bella Vista_Bella Vista LCP495-5	4,460	0	0	0	1	0
32	RPOUT Pierson-Whitefish LCP 603	21,107	3	2	0	2	0
33	RPOUT Hull St_Cranberry LCP-021 Fuses**	7,716	2	2	0	1	0
34	RPOUT ROCKFORD_SUMMIT LCP 565	3,774	3	0	1	1	1
35	RPOUT NORTH PARK_COIT LCP-474**	626	0	0	1	0	0
36	RPOUT LINDEN N LINDEN LCP 720	13,958	0	0	0	1	0
37	RPOUT RANKIN_TRAPANI LCP 337	42,995	0	1	2	0	0
38	RPOUT Kearsley/Shillelagh LCP 599	115,569	3	1	0	1	0
39	RPOUT StanleyNorthland Sub Reach	11,942	1	2	0	2	0
40	RPOUT SLOAN LAVELLE LCP 319	9,794	1	0	1	0	0
41	RPOUT Mayfair Cass LCP 832	8,227	2	1	0	1	0
42	RPOUT Clio/Pine Run LCP 771	59,061	0	0	1	0	0
43	RPOUT STANLEY NORTHLAND TLM 0856241204	409	3	3	1	2	0
44	RPOUT Kearsley/Craig TLM 0857342305	51,690	3	0	4	0	0
45	RPOUT IRISH ROAD_CRYSTALWOOD LCP 196	67,201	3	5	0	3	0
46	SYSP WEST FENTON NORTH ROAD LCP#702	166,667	1	4	1	0	0
47	RPOUT Otisville/Irish Rd LCP 591	45,621	2	0	1	0	1
48	RPOUT RUSSELLVILLE/RICHFIELD LCP 435	107,638	0	4	1	1	0
49	SYSP WEST FENTON OVERPASS LCP#329	35,833	2	5	0	2	0
50	RPOUT BEERS-SHARP LCP 281	9,242	0	0	0	3	0
51	RPOUT - GRANT-GRANT - LCP 355	14,936	3	1	1	2	1
52	RPOUT - GRANT-CATALPA - LCP 380	66,685	5	1	2	0	0
53	RPOUT HESPERIA_RURAL LCP 938	11,491	1	0	0	8	0
54	RPOUT Washington_Madison LCP 423	3,958	1	2	0	0	0
55	RPOUT BALDWIN IDLEWILD LCP 267	4,959	3	0	2	0	1
56	RPOUT WASHINGTON_CONRAD LCP 429	1,879	2	0	0	0	0
57	RPOUT SCOTTVILLE US31 LCP 397	7,131	1	2	4	1	0
58	RPOUT ORIOLE_WHITTIER LCP 385	1,861	3	0	0	1	0
59	RPOUT MANISTEE_LAKE MICHIGAN LCP 070	3,088	2	0	0	0	1
60	RPOUT BALDWIN_IDLEWILD LCP 463	3,457	3	1	2	2	1
61	RPOUT AGNEW ROBINSON	18,354	1	0	1	1	0
62	RPOUT HAYES STREET BUCCANEER	18,675	1	0	3	1	0
63	RPOUT NESTROM_SOUTH SHORE LCP 546	224,779	2	5	2	5	0

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of 2023 and 2024 LVD Repetitive Outages Investment

Case No: U-21870
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Witness: JMPartlan
Date: June 2025

Line		2024	Outage Data				
No.	Project Name	Actual Spending ($)	2021 Outages	2022 Outages	2023 Outages	2024 Outages	2025 outages as of 5/1/25
1	RPOUT TWIN LAKE_TWIN LAKE LCP 604	5,339	0	0	3	1	0
2	RPOUT WHITEHALL_ALICE LCP 874	7,848	1	1	3	4	0
3	RPOUT TERRACE_MALL LCP 362	9,559	1	0	3	0	0
4	RPOUT HYDE PARK_DUCK LAKE LCP 279	2,242	0	0	0	1	0
5	RPOUT ROTHBURY_FERRY LCP 457	2,102	0	1	0	0	1
6	RPOUT SHELBY_PINE STREET LCP 704	2,263	0	0	0	1	0
7	RPOUT GETTY MARQUETTE LCP 848	3,740	3	0	1	1	1
8	RPOUT BENSTON_LEWIS LCP 0633	1,619	0	0	0	1	0
9	RPOUT TWIN LAKE_RILEY THOMPSON LCP 344	2,207	2	1	0	4	0
10	RPOUT TWIN LAKE_RILEY THOMPSON LCP 247	16,228	1	0	2	3	0
11	RPOUT NESTROM_SOUTH SHORE	3,677	2	5	2	5	0
12	RPOUT NORTH MUSKEGON_DALTON LCP 279	3,949	0	0	1	4	0
13	RPOUT TWIN LAKE_TWIN LAKE LCP 568	1,706	3	2	0	6	0
14	RPOUT DUPONT_OLD CHANNEL LCP 415	22,878	1	0	3	5	0
15	SYSP18 SMALLWOOD DAM WOODEN SHOE LCP 930	3,903	1	3	4	1	2
16	RLBY20 SURREY SURREY LCP 188	49,473	5	1	1	1	0
17	SYSP20 EIGHT POINT WHT BIRCH LCP 298	3,780	2	4	1	2	0
18	SYSP18 FROST LONG LAKE LCP 535	1,262	4	2	3	5	1
19	SYSP18 SURREY SURREY LCP 699	439	5	4	0	2	0
20	RPOUT24 HARRISON HARRISON LCP 5926	10,336	1	2	1	6	1
21	SYSP ALCONA DAM_CURTISVILLE	1,075	0	1	0	5	0
22	SYSP EAST TAWAS_LINCOLN STREET	11,658	2	0	1	2	0
23	RPOUT BACKUS-SPRINGBROOK COORD	65,225	4	3	1	5	1
24	RPOUT18 ONEKAMA-CHIEF LCP 608	189	1	3	2	2	3
25	RPOUT Frankfort-Crystallia LCP 397	15,228	5	2	5	1	2
26	RPOUT ARCADIA-PLEASANTON LCP 8567	739	3	3	2	4	2
27	RPOUT ARCADIA-STARKE MULT LCP	6,380	0	0	0	1	1
28	RPOUT HIGH BRIDGE-KALEVA LCP 874	7,764	0	2	1	0	0
29	RPOUT HONOR_PLATTE LCP 0594	4,028	1	3	3	1	1
30	RPOUT HIGH BRIDGE-CREAMERY LCP 900	2,489	0	0	0	2	0
31	RPOUT PELLSTON_BURT LAKE LCP 516	2,800	0	3	2	0	2
32	RPOUT WOODWARD-WOODWARD LK 23 RD	7,179	1	2	1	1	0
33	RPOUT ZONAL FUSE INSTALL 0380_02	29,414	3	1	2	2	1
34	RPOUT 22 BROUGHWELL MINARD LCP	225,750	3	4	5	4	1
35	RPOUT24 BATTEESE_PLEASANT LAKE	10,077	0	0	2	0	0
36	ATR22W UG CLARK LK-EAGLE-DARE 13 HAYES	790	0	0	0	1	0
37	SYSP Bath-Park Lake	63,486	0	0	0	1	0
38	RPOUT BATH SUB - BATH CKT LCP 215	88,786	2	5	1	1	0
39	VOLT WHITTUM KINNEVILLE INSTALL RE-REG	9,314	1	0	1	3	1
40	SYSP MASON SOUTH ST. FUSE COORDINATION	9,953	0	0	1	0	2
41	Dare Perry Perry Rep LCP 595/140A reclos	16,189	1	2	4	2	0
42	RLBY LAINGSBURG_LELAND ROAD LCP 447	4,719	3	3	3	4	4
43	RPOut Athens - Athens LCP 494	2,329	3	0	1	3	0
44	RPOUT14 Pennfield/Pennfield LCP504 #1	930	4	2	1	2	0
45	RPOUT Alder Creek - Lee Lake LCP 221	14,343	4	5	2	0	0
46	RPOUT HASTINGS HANOVER LCP 630	89,886	3	0	0	1	0
47	FUSE24 HASTINGS_BOLTWOOD - ESIC OHL	13,730	3	0	0	0	0
48	RPOUT RIX ROAD_UNDERPASS LCP 637	245	0	4	2	8	2
49	RPOUT SCOTTS-SCOTTS	468	1	0	0	1	0
50	RPOUT RICHLAND-D AVE	2,221	0	0	1	0	0
51	RPOUT LAWRENCE_BRUSH CREEK ESIC OHL	40,978	4	0	0	1	0
52	RPOUT22 ALAMO_FISH HATCHERY 209	52,015	1	3	1	1	0
53	RPOUT PICKEREL_EAST LAKE LCP 278 *317	83,635	3	0	0	2	0
54	RPOUT ALAMO-PINE GROVE_LCP 844 *412	62,583	3	5	1	4	0
55	RPOUT KILGORE WISTERIA	71,574	1	0	2	0	0
56	RPOUT MILLERS POINT_HOLIDAY LCP SUB	22,144	1	0	1	0	0
57	RPOUT UGL KILGORE MILHAM-TRADE CENTER WA	704,049	0	0	0	3	1
58	604 GOLDEN DR, KZO -	73,856	0	2	0	0	0
59	RPOUT HOMER_INDUSTRIAL LCP 685	3,121	4	4	3	0	0
60	RPOUT DOBSON ROAD_HALF MOON LCP 275	8,073	5	1	8	0	0
61	RPOUT LITCHFIELD_QUAKER LAKE PH SWAPS	24,858	0	0	4	0	1
62	RPOUT - Reading City Various fusing	14,524	0	0	4	0	0
63	LNDC RPOUT CEMI12 QUINCY_QUINCY OHL	1,000	2	2	3	2	0
64	RPOUT CEMI12 QUINCY_QUINCY OHL PART 2 *4	38,296	4	1	3	0	1
65	FAIL24READING-CAMBRIA-7510 READING RD-RE	26,599	2	3	0	0	0
66	RPOUT CEMI12 QUINCY_QUINCY OHL *DAYBURG.	134,487	2	3	0	0	0
67	RPOUT CARLETON RD_GAIGE RD	16,073	0	1	2	0	0
68	RPOUT CEMI12 QUINCY_QUINCY UGS	234	2	3	0	0	0
69	RPOUT FILLMORE_64TH STREET LCP SUB	132,635	3	1	0	0	0
70	RPOUT Standale_Parkside LCP 156	2,719	0	0	0	0	0
71	RPOUT BYRON CENTER-RAILSIDE LCP 375	10,625	0	0	0	1	0
72	RPOUT Rivertown_56th LCP 941	1,870	2	0	1	0	0
73	RPOUT STANDALE_STANDALE LCP 356	1,427	0	0	0	0	0
74	RPOUT LOGISTIC FELCH LCP 837	51,188	5	1	1	2	2
75	RPOUT SWAN CREEK MINING LCP 834 -OHL	53,286	4	0	0	0	0
76	RPOUT BUCHANAN-SANDY SHORES *outage card	36,925	0	1	0	0	0
77	RPOUT LOGISTIC FELCH LCP 329	2,296	0	0	1	2	1
78	RPOUT HOPKINS MONTEREY LCP 932	5,286	2	0	0	0	0
79	RPOUT MILL GROVE_ALLEGAN HYDRO LCP 378 *	11,607	3	5	5	1	0
80	RPOUT HAMILTON_HAWKEYE LCP 848B **OUTAGE	70,105	1	0	0	0	0
81	RPOUT HAMILTON-OVERISEL 665 788 889 918	2,951	1	0	0	0	0
82	RPOUT MERSON DUCK LAKE LCP 961 *outage c	59,516	3	1	5	2	0

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBIT

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2020 through 2027
($000's)

Case No.: U-21870
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.9
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Witness: DASchmoekel
Date: June 2025

Streetlight Capital Expenditures
($000)

Line No.	(a) Description	(b) 2020 Actuals	(c) 2021 Actuals	(d) 2022 Actuals	(e) 2023 Actuals	(f) Historical 12 Months Ended 12/31/2024	(g) Projected Bridge Period 12 Mos Ended 12/31/2025	(h) Projected Bridge Period 4 Mos Ending 4/30/2026	(i) Projected Bridge Period 16 Mos Ending 4/30/2026	(j) Projected Test Year 12 Mos Ending 4/30/2027
1	New Business	$ 4,957	$ 2,320	$ 2,799	$ 2,524	$ 5,178	$ 3,630	$ 1,239	$ 4,869	$ 3,727
2	Planned Conversions - Mercury Vapor	$ 1,119							$ -	
3	Planned Conversions - Center Suspension		$ 1,023	$ 77					$ -	
4	Planned Conversions - Vicinity Conversions			$ 805	$ 412	$ 236	$ 1,000	$ 334	$ 1,334	$ 1,018
5	Demand Failures	$ 11,853	$ 12,210	$ 11,220	$ 8,769	$ 13,127	$ 15,998	$ 4,231	$ 20,229	$ 11,800
6	Grand Total	$ 17,929	$ 15,553	$ 14,901	$ 11,705	$ 18,541	$ 20,628	$ 5,804	$ 26,432	$ 16,545

Notes:
1 5-year average for demand failures and new business escalated by 2.1% for 2025
2 5-year average for demand failures and new business escalated by 2.4% for 2026
3 5-year average for demand failures and new business escalated by 0.8% for 2027

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 26 Mos Ending 2/28/2027
7	New Business	$ 1,210	$ 3,659	$ 3,727	$ 8,597
8	Planned Conversions - Mercury Vapor				
9	Planned Conversions - Center Suspension				
10	Planned Conversions - Vicinity Conversions	$ 333	$ 1,001	$ 1,018	$ 2,352
11	Demand Failures	$ 5,333	$ 14,896	$ 11,800	$ 32,029
12	Grand Total	$ 6,876	$ 19,556	$ 16,545	$ 42,978

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2020 through 2027

Case No.: U-21870
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Streetlight Capital Expenditures
Unit Costs

Line No.	(a) Description	(b) 2020 Actuals	(c) 2021 Actuals	(d) 2022 Actuals	(e) 2023 Actuals	(f) Historical 12 Months Ended 12/31/2024	(g) Projected Bridge Period 12 Mos Ended 12/31/2025	(h) Projected Bridge Period 4 Mos Ending 4/30/2026	(i) Projected Bridge Period 16 Mos Ending 4/30/2026	(j) Projected Test Year 12 Mos Ending 4/30/2027
1	New Business Units	268	188	242	195	208	220	73	294	220
2	New Business Unit Cost	$ 18,497	$ 12,339	$ 11,565	$ 12,945	$ 24,895	$ 16,486	$ 16,882	$ 16,585	$ 16,927
3	Planned Conversions - Mercury Vapor (MV)	1,325								
4	Planned Conversions Unit Cost - MV	$ 845								
5	Planned Conversions - Center Suspension (CS)		183	19						
6	Planned Conversions Unit Cost - CS		$ 5,590	$ 4,053						
7	Planned Conversions - Vicinity Conversions (VC)			1,788	783	478	1,060	353	1,413	1,040
8	Planned Conversions Unit Cost - VC			$ 450	$ 526	$ 493	$ 505	$ 946	$ 944	$ 979
9	Demand Failures	15,310	15,775	16,407	11,974	21,205	15,021	5,007	20,028	13,800
10	Demand Failures Unit Costs	$ 774	$ 774	$ 684	$ 732	$ 619	$ 1,065	$ 845	$ 1,010	$ 855

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 26 Mos Ending 2/28/2027
11	New Business Units	73	220	220	514
12	New Business Unit Cost	$ 16,486	$ 16,618	$ 16,927	$ 16,732
13	Planned Conversions - Mercury Vapor (MV)				
14	Planned Conversions Unit Cost - MV				
15	Planned Conversions - Center Suspension (CS)				
16	Planned Conversions Unit Cost - CS				
17	Planned Conversions - Vicinity Conversions (VC)	353	1,060	1,040	2,453
18	Planned Conversions Unit Cost - VC	943	944	979	$ 959
19	Demand Failures	5,007	15,021	13,800	33,828
20	Demand Failures Unit Costs	$ 1,065	$ 992	$ 855	$ 947

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Streetlight Capital Expenditures

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024	(c) Projected Bridge Period 12 Months Ending 12/31/2025	(d) Projected Bridge Period 4 Months Ending 4/30/2026	(e) Projected Bridge Period 14 Months Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
	New Business					
1	Contractor	$ 960	$ 673	$ 230	$ 902	$ 691
2	Labor	$ 1,015	$ 712	$ 243	$ 955	$ 731
3	Materials	$ 1,464	$ 1,026	$ 350	$ 1,377	$ 1,054
4	Business Expenses	$ 9	$ 6	$ 2	$ 9	$ 7
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 1,730	$ 1,213	$ 414	$ 1,627	$ 1,245
	SubTotal	$ 5,178	$ 3,630	$ 1,239	$ 4,869	$ 3,727
	Planned Conversions					
1	Contractor	$ 43	$ 181	$ 60	$ 242	$ 184
2	Labor	$ 21	$ 91	$ 30	$ 122	$ 93
3	Materials	$ 89	$ 378	$ 126	$ 505	$ 385
4	Business Expenses	$ -	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 82	$ 350	$ 117	$ 466	$ 356
	SubTotal	$ 236	$ 1,000	$ 334	$ 1,334	$ 1,018
	Demand Failures					
1	Contractor	$ 826	$ 1,007	$ 266	$ 1,273	$ 742
2	Labor	$ 1,611	$ 1,964	$ 519	$ 2,483	$ 1,449
3	Materials	$ 5,937	$ 7,235	$ 1,914	$ 9,149	$ 5,337
4	Business Expenses	$ -	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 4,753	$ 5,792	$ 1,532	$ 7,324	$ 4,272
	SubTotal	$ 13,127	$ 15,998	$ 4,231	$ 20,229	$ 11,800
	Total Streetlighting					
1	Contractor	$ 1,828	$ 1,861	$ 556	$ 2,417	$ 1,618
2	Labor	$ 2,648	$ 2,767	$ 793	$ 3,560	$ 2,272
3	Materials	$ 7,490	$ 8,640	$ 2,390	$ 11,030	$ 6,776
4	Business Expenses	$ 9	$ 6	$ 2	$ 9	$ 7
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 6,565	$ 7,354	$ 2,063	$ 9,417	$ 5,873
	Total	$ 18,541	$ 20,628	$ 5,804	$ 26,432	$ 16,545

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.9
Page: 4 of 4
Witness: DASchmoekel
Date: June 2025

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Streetlight Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**4 Mos Ending 4/30/2025**	**12 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**26 Mos Ending 2/28/2027**
	New Business				
1	Contractor	$ 224	$ 678	$ 691	$ 1,593
2	Labor	$ 237	$ 717	$ 731	$ 1,686
3	Materials	$ 342	$ 1,035	$ 1,054	$ 2,431
4	Business Expenses	$ 2	$ 6	$ 7	$ 15
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 404	$ 1,222	$ 1,245	$ 2,872
	SubTotal	$ 1,210	$ 3,659	$ 3,727	$ 8,597
	Planned Conversions				
1	Contractor	$ 60	$ 181	$ 184	$ 426
2	Labor	$ 30	$ 91	$ 93	$ 214
3	Materials	$ 126	$ 379	$ 385	$ 890
4	Business Expenses	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 117	$ 350	$ 356	$ 822
	SubTotal	$ 333	$ 1,001	$ 1,018	$ 2,352
	Demand Failures				
1	Contractor	$ 336	$ 937	$ 742	$ 2,015
2	Labor	$ 655	$ 1,829	$ 1,449	$ 3,932
3	Materials	$ 2,412	$ 6,737	$ 5,337	$ 14,486
4	Business Expenses	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 1,931	$ 5,393	$ 4,272	$ 11,596
	SubTotal	$ 5,333	$ 14,896	$ 11,800	$ 32,029
	Total Streetlighting				
1	Contractor	$ 620	$ 1,797	$ 1,618	$ 4,035
2	Labor	$ 922	$ 2,637	$ 2,272	$ 5,832
3	Materials	$ 2,880	$ 8,150	$ 6,776	$ 17,806
4	Business Expenses	$ 2	$ 6	$ 7	$ 15
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 2,451	$ 6,966	$ 5,873	$ 15,290
	Total	$ 6,876	$ 19,556	$ 16,545	$ 42,978

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

REDACTED

EXHIBITS

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Line Clearing O&M Expense
2020-2024 Historical and 2025-2030 Projected

Case No.: U-21870
Exhibit No.: A-170 (SES-1)
Page: 1 of 1
Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Electric System	Expense Type	Year	2020	2021	2022	2023	2024	2025 Calendar Year	2026 Calendar Year	2027 Calendar Year	2028 Calendar Year	2029 Calendar Year	2030 Calendar Year	Total O&M Expense Test Period 5/1/26-4/30/27	Baseline O&M Expense Test Period 5/1/26-4/30/27
				Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
2	**Electric HVD**			**$9,169,948**	**$10,739,347**	**$10,987,343**	**$11,301,449**	**$10,729,853**	**$12,204,000**	**$11,986,720**	**$11,545,541**	**$11,200,000**	**$11,399,117**	**$11,601,293**	**$11,839,660**	**$11,839,660**
3		Contractor	Maintenance Clearing	$4,511,969	$4,488,246	$5,157,938	$4,775,712	$4,010,456	$4,781,847	$4,886,488	$4,838,099	$4,769,923	$4,840,779	$4,913,800	$4,870,358	$4,870,358
4		Contractor	Brushing - Cut	$2,365,927	$2,797,068	$3,063,144	$3,601,378	$3,704,716	$3,724,000	$3,469,195	$3,052,100	$2,750,000	$2,805,000	$2,861,100	$3,330,163	$3,330,163
5		Contractor	Brushing - Spray	$1,395,683	$2,407,477	$1,565,658	$1,885,968	$2,033,114	$2,490,000	$2,400,000	$2,400,000	$2,400,000	$2,448,000	$2,496,960	$2,400,000	$2,400,000
6		Contractor	Demand Clearing	$110,249	$98,417	$89,478	$41,202	$42,841	$60,000	$60,000	$60,000	$60,000	$61,200	$62,424	$60,000	$60,000
7		Contractor	Noxious Weed Control	$91,873	$95,891	$152,737	$82,545	$87,750	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000
8		Contractor	HVD Contract Planning	Note[1]	Note[1]	$175,749	$294,503	$320,353	$400,000	$408,000	$416,160	$424,483	$432,973	$441,632	$410,720	$410,720
9		Labor	HVD Salaries	$672,387	$751,684	$653,623	$516,139	$452,901	$540,153	$552,037	$564,182	$576,594	$592,165	$606,377	$556,085	$556,085
10		Other	HVD Expenses	$21,859	$100,564	$129,016	$104,003	$77,722	$113,000	$116,000	$120,000	$124,000	$124,000	$124,000	$117,333	$117,333
11			**Miles**	**1,116**	**1,178**	**1,106**	**1,153**	**1,203**	**1,104**	**1,177**	**1,162**	**1,120**	**1,167**	**1,177**	**1,172**	**1,172**
12	**Electric LVD**			**$46,104,489**	**$75,827,808**	**$91,016,131**	**$97,792,024**	**$99,494,748**	**$113,203,000**	**$152,966,707**	**$201,754,636**	**$226,284,918**	**$230,426,753**	**$236,813,097**	**$174,844,314**	**$152,606,207**
13		Contractor	Full-circuit Clearing	$36,613,687	$62,121,855	$76,623,355	$84,128,930	$84,437,501	$96,211,412[1]	$135,674,820	$182,456,463	$205,820,191	$211,461,495	$217,246,123	$156,029,100	$134,728,091
14		Contractor	Repetitive Outage Zone	$1,397,354	$1,711,666	$2,086,904	$1,542,258	$1,187,069	$1,200,000	$1,057,600	$900,000	$900,000	$431,561	$400,000	$1,005,067	$1,005,067
15		Contractor	CEMI Clearing	$695,322	$491,257	$506,985	$306,882	$111,203	$500,000	$500,000	$350,000	$300,000	$100,000	$100,000	$450,000	$450,000
16		Contractor	First Zone Clearing	$974,275	$405,771	$466,566	$492,077	$806,271	$1,000,000	$1,000,000	$650,000	$600,000	$200,000	$200,000	$883,333	$883,333
17		Contractor	LCP Zonal Clearing	N/A	N/A	N/A	N/A	$1,049,717	$1,000,000	$800,000	$589,814	$500,000	$100,000	$100,000	$729,938	$729,938
18		Contractor	Demand Clearing	$1,281,844	$3,329,375	$2,737,654	$2,058,822	$2,235,640	$2,500,000	$2,250,000	$1,800,000	$1,710,976	$1,400,000	$1,476,192	$2,100,000	$2,100,000
19		Contractor	Brushing - Spray	$1,538,898	$3,072,427	$3,302,319	$3,396,227	$3,491,649	$3,500,000	$3,500,000	$4,000,000	$4,500,000	$4,500,000	$4,750,000	$3,666,667	$3,666,667
20		Contractor	Distribution Contract Planning/Sup	Note[2]	Note[2]	$1,300,689	$2,274,692	$2,708,070	$2,436,000	$2,662,200	$4,435,170	$5,139,355	$5,242,143	$5,346,985	$3,626,866	$3,253,190
21		Labor	Distribution Salaries	$2,509,359	$3,994,189	$3,120,678	$2,877,300	$2,809,333	$3,787,884	$4,279,163	$5,066,666	$5,188,266	$5,312,784	$5,440,291	$5,027,082	$4,541,664
22		Other	Distribution Expenses	$1,093,749	$701,269	$870,981	$714,837	$658,295	$1,067,704	$1,242,924	$1,506,524	$1,626,130	$1,678,769	$1,753,505	$1,326,261	$1,248,257
23			*LVD Full-circuit Miles*	3,679	4,647	5,653	5,758	5,400	6,108[1]	7,891	10,885	12,814	13,588	14,837	9,019	7,872
24			*LVD Subprogram Clearing Miles*	294	238	247	244	244	244	199	149	137	75	75	181	181
25			*LVD Subprogram Spray Miles*	238	395	488	443	421	413	405	454	501	491	508	422	422
26			**LVD O&M Miles Total**	**4,211**	**5,279**	**6,388**	**6,444**	**6,065**	**6,765**	**8,496**	**11,488**	**13,452**	**14,154**	**15,420**	**9,622**	**8,475**
27	**Electric Total**		**O&M Expense**	**$55,274,437**	**$86,567,155**	**$102,003,474**	**$109,093,473**	**$110,224,601**	**$125,407,000**	**$164,953,427**	**$213,300,177**	**$237,484,918**	**$241,825,870**	**$248,414,390**	**$186,683,974**	**$164,445,867**
28		Contractor	Clearing	$49,489,528	$81,019,448	$95,752,737	$102,312,000	$97,673,165	$113,163,107	$152,193,103	$197,191,476	$219,906,090	$223,943,036	$229,951,599	$171,952,960	$150,651,951
29		Contractor	Brushing - Spray	$2,934,582	$5,479,904	$4,867,977	$5,282,195	$5,524,763	$5,990,000	$5,900,000	$6,400,000	$6,900,000	$6,948,000	$7,246,960	$6,066,667	$6,066,667
30		Contractor	Contract Planning	Note[2], Note[3]	Note[2], Note[3]	$1,476,438	$2,569,195	$3,028,422	$2,836,000	$3,070,200	$4,851,330	$5,563,839	$5,675,115	$5,788,618	$4,037,586	$3,663,910
31		Labor	Salaries	$3,181,745	$4,745,873	$3,774,301	$3,393,439	$3,262,235	$4,328,037	$4,831,200	$5,630,847	$5,764,859	$5,904,949	$6,046,668	$5,583,167	$5,097,749
32		Other	Expenses	$1,115,609	$801,833	$999,997	$818,840	$736,017	$1,180,704	$1,358,924	$1,626,524	$1,750,130	$1,802,769	$1,877,505	$1,443,594	$1,365,590
33			**O&M Miles**	**5,326**	**6,457**	**7,494**	**7,597**	**7,268**	**7,869**	**9,673**	**12,650**	**14,572**	**15,321**	**16,597**	**10,794**	**9,647**
34			HVD Cost/Mile	$8,219	$9,117	$9,932	$9,801	$8,919	$11,054	$10,184	$9,936	$10,000	$9,768	$9,857	$10,102	$10,102
35			LVD Cost/Mile	$10,949	$14,363	$14,248	$15,175	$16,405	$16,733	$18,005	$17,562	$16,822	$16,280	$15,358	$18,172	$18,007
36	**LVD 7-year effective cycle**		LVD Target Cycle Miles	8,362	8,362	8,632	8,699	8,714	8,791							
37			LVD O&M Miles	4,211	5,279	6,388	6,444	6,065	6,765							
38			Capital Clearing Miles	258	252	221	250	258	300							
39			Percent of 7 Year Cycle	53%	66%	77%	77%	73%	80%							
40			Effective Cycle Years	13.1	10.6	9.1	9.1	9.6	8.7							

7-year effective cycle strategy retired

Note[1]: Includes Wildfire Risk Mitigation expenditure and miles
Note[2]: HVD Contract Planners were not recorded separately in 2020 - 2021
Note[3]: LVD Contract Planners were not recorded separately in 2017 - 2021

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Projected LVD Tree-Caused[1] Reliability Impacts of the Line Clearing Ramp-Up Plan

Case No.: U-21870
Exhibit No.: A-171 (SES-2)
Page: 1 of 1
Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Calendar Year**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Actual Line Clearing Program Funding Level ($M)	55.274	86.567	102.003	109.093	110.224						
3	Projected Line Clearing Program Funding Level ($M)						125.407[2]	164.953	213.300	237.485	241.826	248.414
	Excluding MED, All Areas of Fault Including Secondary/Service Outages											
4	Actual Tree-Caused Outage Incidents	13,123	15,442	12,080	12,323	13,631						
5	Actual Tree-Caused SAIFI	0.3128	0.3654	0.3061	0.3103	0.3232						
6	Actual Tree-Caused SAIDI (minutes)	73.20	98.01	67.58	66.08	67.28						
	Excluding MED, Primary and Circuit Outages Only											
7	Actual Tree-Caused Outage Incidents	6,624	7,537	5,757	5,594	6,634						
8	Actual Tree-Caused SAIFI	0.2953	0.3468	0.2952	0.2997	0.3118						
9	Actual Tree-Caused SAIDI (minutes)	68.69	92.54	64.46	62.37	64.40						
10	Projected Tree-Caused Outage Incidents						6,089	6,003	5,816	5,514	5,030	4,450
11	Projected Tree-Caused SAIFI						0.3076	0.3035	0.2947	0.2807	0.2583	0.2316
12	Projected Tree-Caused SAIDI (minutes)						69.99	69.07	67.07	63.87	58.77	52.71
	Including MED, All Areas of Fault Including Secondary/Service Outages											
13	Actual Tree-Caused Outage Incidents	18,564	24,084	16,992	18,228	20,259						
14	Actual Tree-Caused SAIFI	0.4867	0.6765	0.4855	0.5334	0.5524						
15	Actual Tree-Caused SAIDI (minutes)	255.47	519.03	235.65	471.07	267.80						
	Including MED, Primary and Circuit Outages Only											
16	Actual Tree-Caused Outage Incidents	9,938	12,665	8,226	8,489	10,202						
17	Actual Tree-Caused SAIFI	0.4629	0.6466	0.4709	0.5180	0.5361						
18	Actual Tree-Caused SAIDI (minutes)	242.09	495.48	228.02	457.68	259.28						
19	Projected Tree-Caused Outage Incidents						9,341	9,157	8,804	8,271	7,472	6,565
20	Projected Tree-Caused SAIFI						0.5211	0.5116	0.4933	0.4659	0.4251	0.3791
21	Projected Tree-Caused SAIDI (minutes)						332.63	326.26	314.05	295.77	268.50	237.77

[1] Includes outages with cause codes Trees and Trees - Outside ROW

[2] Includes funding authorized in Case No. U-21585 for additional line clearing for wildfire risk mitigation

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025 HVD Line Clearing Work Plan

Case No.: U-21870
Exhibit No.: A-172 (SES-3)
Page: 1 of 1
Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Line Name	Miles	Voltage	Year Last Cleared	Line Name	Miles	Voltage	Year Last Cleared
1	ACUGLASS	20.46	138	2021	KENT CITY	30.1	46	2021
2	ALMA-BEGOLE	0.98	138	2021	KILGORE	4.08	46	2021
3	ALPENA-IOSCO	0.04	138	2021	KIRK ST	1.86	23	2021
4	AMASTEEL	1.42	138	2021	KNIGHT	14.85	46	2021
5	ARGENTA-MILHAM	1.13	138	2021	L-12	1.35	138	2021
6	BALDWIN	9.29	46	2021	LAKE CITY	16.1	46	2021
7	BALLENGER	3.51	46	2021	LAKE ODESSA	15.88	46	2021
8	BATH	22.35	46	2021	MACKINAW	5.48	46	2021
9	BEAVER CREEK - HIGGINS	0.05	138	2021	MAPLE GROVE	2.17	46	2021
10	BELSAY	7.26	46	2021	MARSHALL - BLACKSTONE	0.1	138	2021
11	BEVERIDGE - VAN SLYKE	3.2	46	2021	MAUMEE	2.3	46	2021
12	BLACK RIVER	12.01	46	2021	MCBAIN	21.23	46	2021
13	BRISTOL	8.28	46	2021	MENDON	31.8	46	2021
14	BULLOCK-SAGINAW RIVER	0.12	138	2021	MERSON	8.68	46	2021
15	CADILLAC	1.87	46	2021	MIO - AIRPORT	0.04	138	2021
16	CADILLAC CO-GEN	0.86	46	2021	MIO - GAYLORD	1.88	138	2021
17	CAMPUS	5.69	46	2021	MONA LAKE	10.72	46	2021
18	CASINO	14.89	46	2021	MT PLEASANT	0.1	46	2020
19	CHEBOYGAN	11.64	46	2021	MUSKEGON #2	0.46	138	2021
20	CHELSEA	1.12	46	2021	NEW HAVEN	1.46	46	2021
21	CHRYSLER	11.91	46	2021	NEW RICHMOND	15.01	46	2021
22	CLAREMONT-CORNELL	0.01	138	2021	NEWAYGO	17.86	46	2021
23	CLAREMONT-MANNING	0.37	138	2021	NIAGRA	6.42	46	2021
24	COBB - TALLMADGE	5.22	138	2021	ORR RD	0.58	138	2021
25	COLLEGE PARK	3.26	46	2021	PARR RD-WHITING	0.47	138	2021
26	CROTON - FOUR MILE	8.58	138	2021	PATTERSON	9.19	46	2021
27	CROTON-MECOSTA	0.23	138	2021	PEACH RIDGE	22.13	46	2021
28	CROTTY	1.47	46	2021	PHILLIPS #1	1.51	46	2021
29	CUMBERLAND	5.66	46	2021	PHILLIPS #2	1.5	46	2021
30	DELHI-TOMPKINS #2	13.9	138	2021	PORTAGE	2.01	46	2021
31	DOW CORNING - BULLOCK	1.83	138	2021	POTTER	4.42	23	2021
32	E GENESEE	1.56	46	2022	PRICE RD	0.02	138	2021
33	EAST JORDAN	19.99	46	2021	RAISIN	1.19	46	2021
34	EATON RAPIDS	34.13	46	2021	RANGER LAKE	24.63	46	2021
35	EDDY	2.12	23	2021	RAVENNA	36.63	46	2021
36	FLAKEBOARD	1.1	138	2021	REED CITY	57.81	46	2021
37	FRUITPORT	15.77	46	2021	RIGGSVILLE - LIVINGSTON	2.67	138	2021
38	GETTY	10.37	46	2021	ROSEBUSH	7.54	46	2021
39	GLEN OAKS	10.23	46	2021	SALZBURG	6.07	46	2022
40	GOSS - BEVERIDGE	0.1	138	2021	SARANAC	13.29	46	2021
41	GRAND BLANC	0.01	46	2021	ST CHARLES	24.3	46	2021
42	GRASS LAKE	28.29	46	2021	STAUFFER	11.8	46	2021
43	GUN LAKE	24.31	46	2021	STOCKBRIDGE	37.78	46	2021
44	HANOVER	33.42	46	2021	SUMMERTON	0.74	138	2021
45	HARLEM	6.13	46	2021	TECUMSEH PRODUCTS	0.89	46	2021
46	HARPER RD	0.1	46	2021	TERRACE	3.04	46	2021
47	HEMPHILL - HALSEY	0.22	138	2022	TRUMBULL	4.46	46	2021
48	HENRY	6.1	46	2021	TUSTIN	13.94	46	2021
49	HICKORY	3.7	46	2021	UNIVERSITY	4.52	46	2021
50	HIGGINS	0.04	138	2021	VENICE	28.46	46	2021
51	HILE ROAD	0.03	138	2021	VIRGINIA PARK	17.33	46	2021
52	HOLTON	0.06	46	2021	WEADOCK - DORT	0.05	138	2022
53	HUDSONVILLE	18.15	46	2021	WEISS	3.58	23	2021
54	HUNT RD	12.03	46	2021	WEST BRANCH	39.79	46	2021
55	INDIAN RIVER	9.54	46	2021	WESTERN AVE	2.14	46	2021
56	ITHACA	12.88	46	2021	WESTERVELT	2.51	23	2021
57	JANES	6.46	46	2022	WESTPHALIA	9.56	46	2021
58	KALAMAZOO TREATMENT	0.3	46	2021	WHITE LAKE-SIKKENGA	0.31	46	
59	KALARAMA	2.43	46	2021	WILLIAMS	22.07	46	2021
60	KEATING	9.41	46	2021	WIRTZ RD	27.71	46	2021
61	Total 2025 Work Plan Miles	1104.16						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025 LVD Line Clearing Work Plan

Case No.: U-21870
Exhibit No.: A-173 (SES-4)
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Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customers Impacted	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
1	000402	COLEMAN	RURAL	CLR	4.8/8.32 kV Wye Grounded	78.94	25.70	999		25					0.00	25.70	2024 Carryover
2	001102	BELLA VISTA	BLAKELY	GRN	4.8/8.32 kV Wye Grounded	30.58	30.58	965	36.37	13	35	0.294	327	31.6	0.00	30.58	
3	002302	BLINTON	VEMCO	FLT	14.4/24.9 kV Wye Grounded	44.05	44.05	2254	190.08	37	42	0.098	824	51.2	0.00	44.05	
4	002401	BEAVERTON	ROSS STREET	CLR	4.8/8.32 kV Wye Grounded	63.98	0.60	933		15					0.00	0.60	2024 Carryover
5	002402	BEAVERTON	TOBACCO	CLR	4.8/8.32 kV Wye Grounded	62.79	62.79	1261	44.22	15	47	0.191	531	20.1	0.00	62.79	
6	002702	MANISTEE	MANISTEE SALT	LDG	7.2 kV Delta	8.15	8.15	462	346.00	13	20	0.041	115	56.7	0.00	8.15	
7	002704	MANISTEE	FILER CITY	LDG	7.2 kV Delta	7.43	7.43	581	353.00	13	16	0.045	118	78.2	0.00	7.43	
8	002801	COOKE DAM	VILLAGE	TWS	4.8/8.32 kV Wye Grounded	29.19	29.19	427	64.86	28	26	0.240	454	14.6	0.00	29.19	
9	002901	SOUTH WASHINGTON	FORDNEY	SAG	4.8/8.32 kV Wye Grounded	7.85	7.85	705	127.00	10	31	0.085	85	89.8	0.00	7.85	
10	003501	CADILLAC	CENTRAL	CAD	4.8/8.32 kV Wye Grounded	10.43	10.43	1323	441.25	9	24	0.128	588	126.8	10.43	0.00	
11	003703	BOMAN	RIVERVIEW	FLT	4.8/8.32 kV Wye Grounded	21.05	21.05	1399	343.60	17	33	0.079	573	66.5	0.00	21.05	
12	004101	TAWAS	EAST TAWAS	TWS	4.8/8.32 kV Wye Grounded	3.67	3.67	360	0.00	37	19	0.000	0	98.1	0.00	3.67	
13	004504	LARKIN	MORNING SIDE	MDL	4.8/8.32 kV Wye Grounded	16.64	16.64	1469	50.67	13	32	0.120	101	88.3	0.00	16.64	
14	005703	CLIO	WEST CLIO	FLT	4.8/8.32 kV Wye Grounded	14.83	14.83	1467	133.67	10	16	0.067	134	98.9	0.00	14.83	
15	006502	BAVARIAN	JEFFERSON	SAG	4.8/8.32 kV Wye Grounded	17.64	17.64	779	201.33	37	19	0.057	201	44.2	0.00	17.64	
16	006801	HOMESTEAD	JOYFIELD	BEN	7.2/12.47 kV Wye Grounded	51.79	51.79	598	78.81	13	28	0.200	814	11.5	0.00	51.79	
17	007303	MILTON	FEDERAL SCREW	BIG	7.2/12.47 kV Wye Grounded	14.06	14.06	721	119.00	17	20	0.166	278	51.3	0.00	14.06	
18	008506	ELM STREET	MONROE	BCK	4.8/8.32 kV Wye Grounded	2.32	2.32	46	0.00	13	8	0.000	0	19.8	0.00	2.32	
19	009201	CHESANING	OAKLEY	SAG	4.8/8.32 kV Wye Grounded	42.54	42.54	790	150.58	18	28	0.094	602	18.6	0.00	42.54	
20	009902	FREELAND	FREELAND	SAG	4.8/8.32 kV Wye Grounded	67.12	67.12	2191	296.60	15	31	0.099	1977	32.6	0.00	67.12	
21	010102	FREMONT	GERBER	FRE	4.8/8.32 kV Wye Grounded	0.51	0.51	2	0.00	28	13	0.000	0	3.9	0.00	0.51	
22	010106	FREMONT	REEMAN	FRE	4.8/8.32 kV Wye Grounded	29.22	29.22	1765	25.00	10	24	0.068	50	60.4	0.00	29.22	
23	010603	ATLAS	GOODRICH	FLT	4.8/8.32 kV Wye Grounded	34.59	34.59	846	161.93	27	33	0.145	810	24.5	0.00	34.59	
24	011003	HASTINGS	BOLTWOOD	HST	4.8/8.32 kV Wye Grounded	97.46	97.46	2512	94.24	12	58	0.116	1068	25.8	0.00	97.46	
25	011202	CAMELOT LAKE	LOOMIS	MDL	14.4/24.9 kV Wye Grounded	54.23	54.23	754	50.67	5	50	0.283	777	13.9	54.23	0.00	
26	011702	LINDEN	NORTH LINDEN	FLT	4.8/8.32 kV Wye Grounded	30.16	30.16	1545	255.14	18	20	0.077	595	51.2	0.00	30.16	
27	012802	EVANSTON	EVANSTON	MUS	7.2/12.47 kV Wye Grounded	41.91	41.91	676	73.97	10	58	0.278	863	16.1	0.00	41.91	
28	014603	GREENSPIRE	COLONY WOODS	KAL	4.8/8.32 kV Wye Grounded	9.23	9.23	394	393.50	36	18	0.072	262	42.7	0.00	9.23	
29	016502	LESLIE INDUSTRIAL	INDUSTRIAL	JAC	4.8/8.32 kV Wye Grounded	7.05	7.05	177	7.00	37	26	0.095	5	25.1	0.00	7.05	
30	017901	STANDISH	STERLING	WBR	4.8/8.32 kV Wye Grounded	2.86	2.86	67	0.00	19	16	0.000	0	23.4	0.00	2.86	
31	018001	CLARKSVILLE	MORRISON LAKE	HST	4.8/8.32 kV Wye Grounded	32.91	32.91	495	106.00	16	24	0.051	177	15.0	0.00	32.91	
32	018501	PULLMAN	CHICORA	HML	4.8/8.32 kV Wye Grounded	63.30	63.30	1255	79.79	14	78	0.353	1782	19.8	0.00	63.30	
33	019602	CONVIS	WALNUT POINT	BCK	14.4/24.9 kV Wye Grounded	98.55	98.55	1118	69.88	8	70	0.200	1374	11.3	0.00	98.55	
34	021702	STATE STREET	WARWICK	SAG	4.8/8.32 kV Wye Grounded	11.04	0.60	1383		12					0.00	0.60	2024 Carryover
35	022201	COWAN LAKE	GRATTAN	GRN	14.4/24.9 kV Wye Grounded	56.60	56.60	1307	104.04	5	96	0.289	1699	23.1	56.60	0.00	
36	022301	CARSON CITY	HOSPITAL	GVL	4.8/8.32 kV Wye Grounded	47.45	47.45	705	42.50	27	45	0.155	312	14.9	0.00	47.45	
37	022503	MIDDLETON	NEWARK	ALM	4.8/8.32 kV Wye Grounded	61.26	61.26	763	28.08	13	43	0.141	243	12.5	0.00	61.26	
38	023102	MENDON	KIRBY	CLD	4.8/8.32 kV Wye Grounded	38.20	38.20	609	47.69	20	28	0.140	254	15.9	0.00	38.20	
39	024103	DOEHLER JARVIS	JEFFERSON	GRA	7.2/12.47 kV Wye Grounded	17.81	17.30	4124		7					17.30	0.00	2024 Carryover
40	024103	DOEHLER JARVIS	JEFFERSON	GRA	7.2/12.47 kV Wye Grounded	17.81	17.81	4124	493.42	7	43	0.225	1974	231.6	17.81	0.00	
41	024201	MCBAIN	LAKE CITY	CAD	14.4 kV Delta	72.89	72.89	774	175.18	10	35	0.078	993	10.6	0.00	72.89	
42	024401	PORTAGE	CARPENTERS CORNERS	KAL	4.8/8.32 kV Wye Grounded	8.25	8.25	695	111.86	37	23	0.283	261	84.2	0.00	8.25	
43	024402	PORTAGE	SHAVER ROAD	KAL	4.8/8.32 kV Wye Grounded	27.68	27.68	1559	283.16	15	39	0.229	1793	56.3	0.00	27.68	
44	024701	RUTLAND	TANNER LAKE	HST	4.8/8.32 kV Wye Grounded	50.55	50.55	685	77.70	14	55	0.198	777	13.6	0.00	50.55	
45	025103	NORTH MUSKEGON	STATE PARK	MUS	7.2/12.47 kV Wye Grounded	30.16	30.16	1922	89.52	9	62	0.464	1253	63.7	0.00	30.16	
46	025202	ONEKAMA	BEAR LAKE	BEN	7.2/12.47 kV Wye Grounded	61.48	60.61	1258		16					0.00	60.61	2024 Carryover
47	025203	ONEKAMA	CHIEF	BEN	7.2/12.47 kV Wye Grounded	69.62	69.62	571	40.68	15	24	0.120	339	8.2	0.00	69.62	
48	025603	BRIDGEPORT	DIXIE	SAG	4.8/8.32 kV Wye Grounded	45.94	2.30	1490		10					0.00	2.30	2024 Carryover
49	025701	OSHTEMO	ALMENA	KAL	4.8/8.32 kV Wye Grounded	39.34	39.34	1055	141.60	17	63	0.364	2030	26.8	0.00	39.34	
50	025804	DEWITT	DEWITT	LAN	4.8/8.32 kV Wye Grounded	43.73	12.70	1295		19					0.00	12.70	2024 Carryover
51	026002	SARANAC	CENTERLINE	GVL	4.8/8.32 kV Wye Grounded	34.36	34.36	507	84.38	10	62	0.388	1125	14.8	0.00	34.36	
52	026502	GUN LAKE	TRAILS END	HST	4.8/8.32 kV Wye Grounded	44.61	11.30	1166		9					11.30	0.00	2024 Carryover
53	027801	DIXIE	HARVARD	FLT	4.8/8.32 kV Wye Grounded	14.90	14.90	1279		26					0.00	14.90	2024 Carryover
54	027902	HAGER PARK	HAGER PARK	GRA	7.2/12.47 kV Wye Grounded	60.02	60.02	4019	689.47	16	27	0.083	3447	67.0	0.00	60.02	

Line No.	(a) Description	(b) Feeder ID	(c) Substation	(d) Circuit	(e) HQ	(f) Voltage	(g) Circuit Miles	(h) Work Plan Miles	(i) Circuit Customers	(j) Average Outages per Incident	(k) Years Since Last Cleared	(l) Relative Risk Score (0-100)	(m) 3-Year Weighted Average Incidents per Mile	(n) Customers Impacted	(o) Customer Density per Mile	(p) On Cycle Miles	Backlog Miles	Notes
55		028202	HOMER	INDUSTRIAL	CLD	4.8/8.32 kV Wye Grounded	79.43	79.43	1019	22.79	14	59	0.138	251	12.8	0.00	79.43	
56		028901	MILLER ROAD	UTLEY ROAD	FLT	4.8/8.32 kV Wye Grounded	6.99	6.99	542	352.00	26	22	0.048	117	77.5	0.00	6.99	
57		029002	BRECKENRIDGE	VILLAGE	ALM	4.8/8.32 kV Wye Grounded	76.54	76.54	1158	61.50	30	18	0.009	41	15.1	0.00	76.54	
58		029101	HAMILTON	HAMILTON	HML	4.8/8.32 kV Wye Grounded	58.65	58.65	1386	101.13	10	50	0.171	1011	23.6	0.00	58.65	
59		029301	MARKEY	MONTYVILLE	WBR	4.8/8.32 kV Wye Grounded	41.12	41.12	2428	269.00	11	60	0.113	1255	59.0	0.00	41.12	
60		029302	MARKEY	CARRICK	WBR	4.8/8.32 kV Wye Grounded	27.99	27.99	1404	379.35	9	33	0.238	2529	50.2	27.99	0.00	
61		029501	STOCKBRIDGE	MORTON	JAC	4.8/8.32 kV Wye Grounded	81.54	81.54	1032	66.00	15	55	0.188	1012	12.7	0.00	81.54	
62		029502	STOCKBRIDGE	STOCKBRIDGE	JAC	4.8/8.32 kV Wye Grounded	8.42	8.42	596	42.50	26	22	0.238	85	70.8	0.00	8.42	
63		029601	VANDERCOOK LAKE	HAGUE ROAD	JAC	4.8/8.32 kV Wye Grounded	28.81	28.81	798	46.91	11	55	0.393	532	27.7	0.00	28.81	
64		029603	VANDERCOOK LAKE	VANDERCOOK LAKE	JAC	4.8/8.32 kV Wye Grounded	13.31	13.31	1116	93.11	9	43	0.451	559	83.8	13.31	0.00	
65		029702	LAMBERTVILLE	SUMMERFIELD	SMN	7.2/12.47 kV Wye Grounded	29.31	29.31	1945	37.00	9	62	0.159	173	66.4	0.00	29.31	
66		030001	ASHLEY	GARFIELD	ALM	4.8/8.32 kV Wye Grounded	57.27	57.24	501		37					0.00	57.24	2024 Carryover
67		030401	WEIDMAN	BEAL CITY	CLR	4.8/8.32 kV Wye Grounded	66.13	66.13	841	64.17	29	49	0.181	770	12.7	0.00	66.13	
68		030501	ORLEANS	LONG LAKE	GVL	4.8/8.32 kV Wye Grounded	46.44	46.44	819	99.39	14	51	0.258	1193	17.6	0.00	46.44	
69		030601	REMUS	MECOSTA	BIG	4.8/8.32 kV Wye Grounded	48.04	8.20	1094		19					0.00	8.20	2024 Carryover
70		030602	REMUS	MILLBROOK	BIG	4.8/8.32 kV Wye Grounded	56.30	9.30	643		22					0.00	9.30	2024 Carryover
71		030901	WALDRON	BETZER	ADR	4.8/8.32 kV Wye Grounded	44.79	44.79	491	54.17	16	24	0.045	108	11.0	0.00	44.79	
72		031102	LAMOREAUX	LAMOREAUX	GRN	7.2/12.47 kV Wye Grounded	10.70	10.70	743	104.43	9	17	0.218	244	69.4	0.00	10.70	
73		031201	LINCOLN	LOST LAKE	TWS	11.0 kV Delta	105.11	104.31	1484		9					0.00	104.31	2024 Carryover
74		031902	BRIDGE STREET	WATER STREET	JAC	4.8/8.32 kV Wye Grounded	8.30	8.30	618	34.50	11	23	0.080	23	74.5	0.00	8.30	
75		032103	ASHMAN CIRCLE	HIGH SCHOOL	MDL	4.8/8.32 kV Wye Grounded	8.14	2.95	1251		30					0.00	2.95	2024 Carryover
76		032501	BOSTON SQUARE	NELAND	GRA	7.2/12.47 kV Wye Grounded	6.71	6.71	1500	122.00	7	18	0.099	81	223.5	6.71	0.00	
77		032503	BOSTON SQUARE	HALL	GRA	7.2/12.47 kV Wye Grounded	10.55	10.55	2055	46.00	7	21	0.032	15	194.8	10.55	0.00	
78		033103	VAN BUREN	RUSH CREEK	GRA	7.2/12.47 kV Wye Grounded	37.28	25.50	1724		37					0.00	25.50	2024 Carryover
79		033302	AU GRES	AU GRES	TWS	12.0 kV Delta	54.16	54.16	1394	80.88	6	53	0.098	431	25.7	0.00	54.16	
80		033702	EAST GRANT	ONION FARMS	FRE	4.8/8.32 kV Wye Grounded	22.98	22.98	241	35.28	37	22	0.261	212	10.5	0.00	22.98	
81		034001	DIMONDALE	M-99	LAN	4.8/8.32 kV Wye Grounded	36.69	36.69	1260	105.36	11	47	0.127	492	34.3	0.00	36.69	
82		034501	KAWKAWLIN	LAGOON BEACH	BCY	4.8/8.32 kV Wye Grounded	24.15	24.15	1284	48.11	9	27	0.124	144	53.2	24.15	0.00	
83		034602	BYRON CENTER	CARLISLE	GRA	7.2/12.47 kV Wye Grounded	56.08	56.08	1615	288.20	9	23	0.030	480	28.8	0.00	56.08	
84		034701	ST CHARLES	FERGUS	SAG	4.8/8.32 kV Wye Grounded	66.92	6.50	1018		13					0.00	6.50	2024 Carryover
85		034702	ST CHARLES	SAGINAW	SAG	4.8/8.32 kV Wye Grounded	51.77	51.71	1084		15					0.00	51.71	2024 Carryover
86		035002	FRUITPORT	JUDSON ROAD	MUS	7.2/12.47 kV Wye Grounded	39.19	39.19	1597	139.11	8	58	0.527	2875	40.8	0.00	39.19	
87		036301	CORUNNA	COURTHOUSE	OWS	4.8/8.32 kV Wye Grounded	8.64	8.64	776	64.00	26	26	0.077	43	89.8	0.00	8.64	
88		036403	IRON STREET	TERM	FLT	4.8/8.32 kV Wye Grounded	10.37	7.90	1250		27					0.00	7.90	2024 Carryover
89		036801	APPLE	CHATTERSON ROAD	MUS	4.8/8.32 kV Wye Grounded	46.45	18.06	1447		37					0.00	18.06	2024 Carryover
90		036906	COOLEY	EXCHANGE	KAL	4.8/8.32 kV Wye Grounded	2.90	2.90	118	0.00	37	11	0.000	0	40.7	0.00	2.90	
91		037301	RAVENNA	RAVENNA	MUS	4.8/8.32 kV Wye Grounded	38.10	38.10	749	116.86	15	51	0.184	818	19.7	0.00	38.10	
92		037602	BATTEESE	PLEASANT LAKE	JAC	14.4/24.9 kV Wye Grounded	63.22	3.40	1413		6					0.00	3.40	2024 Carryover
93		037902	HESPERIA	RURAL	FRE	4.8/8.32 kV Wye Grounded	128.41	3.30	1091		15					0.00	3.30	2024 Carryover
94		039803	SWARTZ CREEK	WINCHESTER	FLT	4.8/8.32 kV Wye Grounded	19.48	19.48	1338		26					0.00	19.48	2024 Carryover
95		040501	LASALLE	DIXIE	SMN	7.2/12.47 kV Wye Grounded	19.91	19.91	641	40.11	9	27	0.151	120	32.2	0.00	19.91	
96		041001	FLUSHING	MARY STREET	FLT	4.8/8.32 kV Wye Grounded	22.30	22.30	1307	96.18	14	32	0.164	353	58.6	0.00	22.30	
97		041002	FLUSHING	SEYMOUR ROAD	FLT	4.8/8.32 kV Wye Grounded	39.44	32.70	1190		17					0.00	32.70	2024 Carryover
98		041104	KELLOGGSVILLE	MAJESTIC	GRA	7.2/12.47 kV Wye Grounded	15.18	15.18	2164	522.00	25	21	0.022	174	142.6	0.00	15.18	
99		041201	SYLVAN	CITY	JAC	4.8/8.32 kV Wye Grounded	63.01	42.10	854		10					0.00	42.10	2024 Carryover
100		041501	GLENDALE	HILLTOP	KAL	4.8/8.32 kV Wye Grounded	0.56	0.56	21	0.00	24	14	0.000	0	37.5	0.00	0.56	
101		041503	GLENDALE	HERCULES	KAL	4.8/8.32 kV Wye Grounded	9.90	9.90	1074		11					0.00	9.90	2024 Carryover
102		041602	WHITTUM	ROYSTON	LAN	4.8/8.32 kV Wye Grounded	51.60	51.60	610	79.82	15	32	0.142	585	11.8	0.00	51.60	
103		042303	GERRISH	COTTAGE GROVE	WBR	4.8/8.32 kV Wye Grounded	32.87	32.93	1076		9					32.93	0.00	2024 Carryover
104		042304	GERRISH	MERRIO	WBR	4.8/8.32 kV Wye Grounded	19.70	5.20	258		32					0.00	5.20	2024 Carryover
105		042402	MARION	MILL	CAD	14.4 kV Delta	45.92	45.92	631	98.20	15	28	0.036	164	13.7	0.00	45.92	
106		046501	DIVISION	PARKER	GRA	7.2/12.47 kV Wye Grounded	10.85	10.85	787	743.67	31	22	0.184	1487	72.5	0.00	10.85	
107		048902	MT FOREST	BENTLEY	BCY	4.8/8.32 kV Wye Grounded	106.59	106.26	1003		14					0.00	106.26	2024 Carryover
108		049402	SHATTUCK	CENTER ROAD	SAG	4.8/8.32 kV Wye Grounded	8.21	8.21	1060	100.00	13	16	0.081	67	129.1	0.00	8.21	

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	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customers Impacted	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
109	050202	WYOMING PARK	PORTER	GRA	7.2/12.47 kV Wye Grounded	9.54	9.54	945	945.00	9	16	0.035	315	99.1	0.00	9.54	
110	050902	LETTS ROAD	MONROE ROAD	MDL	14.4/24.9 kV Wye Grounded	43.88	20.90	1056		18					0.00	20.90	2024 Carryover
111	051101	MANCELONA	ALBA	TRA	7.2/12.47 kV Wye Grounded	79.00	1.50	1645		15					0.00	1.50	2024 Carryover
112	051202	NESTROM	SOUTH SHORE	MUS	7.2/12.47 kV Wye Grounded	48.28	48.28	1125	94.30	8	93	0.670	3049	23.3	0.00	48.28	
113	052002	WHITEHALL	ALICE	MUS	7.2/12.47 kV Wye Grounded	10.10	10.10	800	265.12	11	32	0.561	1502	79.2	0.00	10.10	
114	052301	WOOD STREET	AVENUE A	FLT	4.8/8.32 kV Wye Grounded	2.03	2.03	163	0.00	31	13	0.000	0	80.3	0.00	2.03	
115	052303	WOOD STREET	CHIPPEWA	FLT	4.8/8.32 kV Wye Grounded	1.64	1.64	140	0.00	37	15	0.000	0	85.4	0.00	1.64	
116	053701	TWIN LAKE	TWIN LAKE	MUS	4.8/8.32 kV Wye Grounded	51.53	51.53	1769	113.87	19	79	0.388	2277	34.3	0.00	51.53	
117	055702	EAST LAKE	PINE CREEK	LDG	7.2/12.47 kV Wye Grounded	59.44	52.60	634		9					0.00	52.60	2024 Carryover
118	057101	CASCO	BLUFF	HML	4.8/8.32 kV Wye Grounded	51.50	51.50	1236	103.10	10	43	0.136	722	24.0	0.00	51.50	
119	057102	CASCO	HAWKHEAD	HML	4.8/8.32 kV Wye Grounded	62.24	43.50	1006		13					0.00	43.50	2024 Carryover
120	057501	MORRICE	M-78	OWS	4.8/8.32 kV Wye Grounded	31.19	31.19	666	58.13	16	24	0.171	310	21.4	0.00	31.19	
121	057502	MORRICE	SOUTH MORRICE	OWS	4.8/8.32 kV Wye Grounded	73.33	73.33	977	175.75	13	32	0.073	937	13.3	0.00	73.33	
122	057602	POTTERVILLE	M-78	LAN	4.8/8.32 kV Wye Grounded	83.40	83.40	1442	132.37	23	75	0.204	2250	17.3	0.00	83.40	
123	057802	VIRGINIA PARK	MACATAWA	HML	4.8/8.32 kV Wye Grounded	24.11	24.11	1225	201.14	9	31	0.194	939	50.8	24.11	0.00	
124	058606	LEITH STREET	LEITH	FLT	4.8/8.32 kV Wye Grounded	17.12	17.12	2050	50.25	11	71	0.078	67	119.7	0.00	17.12	
125	058901	THORNAPPLE	HEADLEY	GRE	4.8/8.32 kV Wye Grounded	21.50	21.50	714	72.78	10	62	0.574	898	33.2	0.00	21.50	
126	060202	TRUFANT	GOWEN	GVL	4.8/8.32 kV Wye Grounded	45.88	31.50	1113		13					0.00	31.50	2024 Carryover
127	060204	TRUFANT	TRUFANT	GVL	4.8/8.32 kV Wye Grounded	29.32	29.32	504	83.73	9	46	0.171	419	17.2	29.32	0.00	
128	060803	PALMER	LAKESIDE	KAL	4.8/8.32 kV Wye Grounded	10.26	6.71	286		9					6.71	0.00	2024 Carryover
129	061102	KENDALL	SAGE	KAL	4.8/8.32 kV Wye Grounded	15.88	15.88	2456	349.13	11	32	0.168	931	154.7	0.00	15.88	
130	061502	SCOTTS	SCOTTS	KAL	4.8/8.32 kV Wye Grounded	73.51	1.50	752		14					0.00	1.50	2024 Carryover
131	061701	FRANKFORT	FRANKFORT	BEN	7.2/12.47 kV Wye Grounded	1.70	1.70	350	0.00	10	12	0.000	0	205.9	0.00	1.70	
132	062901	COOPERSVILLE	CONKLIN	MUS	4.8/8.32 kV Wye Grounded	25.78	25.78	1335	94.71	15	24	0.091	221	51.8	0.00	25.78	
133	063702	PLAINFIELD	BELMONT	GRN	4.8/8.32 kV Wye Grounded	20.85	20.85	1311	134.64	10	27	0.224	628	62.9	0.00	20.85	
134	063901	PARNALL	CONSUMERS #1	JAC	4.8/8.32 kV Wye Grounded	1.05	1.05	2	0.00	37	13	0.000	0	1.9	0.00	1.05	
135	064101	BAYBERRY	KOSTER	GRA	7.2/12.47 kV Wye Grounded	14.53	14.53	610	68.25	37	30	0.184	182	42.0	0.00	14.53	
136	065701	EAST JORDAN	WILLIAMS STREET	BNC	7.2/12.47 kV Wye Grounded	14.20	9.50	433		10					0.00	9.50	2024 Carryover
137	066302	LEHRING	MYERS LAKE	OWS	4.8/8.32 kV Wye Grounded	83.17	9.40	1477		18					0.00	9.40	2024 Carryover
138	066602	ENSLEY	BAPTIST LAKE	BIG	4.8/8.32 kV Wye Grounded	37.44	37.44	633		13					0.00	37.44	2024 Carryover
139	066802	CARROLL	CARROLL	JAC	4.8/8.32 kV Wye Grounded	2.77	2.77	186	39.33	37	22	0.361	39	67.1	0.00	2.77	
140	069802	HOGAN ROAD	ROLSTON	FLT	4.8/8.32 kV Wye Grounded	15.72	15.72	979	316.33	15	24	0.254	1265	62.3	0.00	15.72	
141	070104	WALNUT	GILKEY	FLT	4.8/8.32 kV Wye Grounded	9.59	9.59	1164	73.50	19	40	0.070	49	121.4	0.00	9.59	
142	070202	MAGNUS	MCKAY FARM	CLR	4.8/8.32 kV Wye Grounded	60.80	60.80	858	75.69	12	29	0.071	328	14.1	0.00	60.80	
143	070604	BOWEN	KIMBERLY	GRA	7.2/12.47 kV Wye Grounded	9.19	9.19	1123	154.00	11	16	0.036	51	122.2	0.00	9.19	
144	070702	STEVENS	BUCHANAN	GRA	7.2/12.47 kV Wye Grounded	0.01	0.01	0	0.00	27	11	0.000	0	0.0	0.00	0.01	
145	070802	MICHIGAN	LOOKOUT	GRA	7.2/12.47 kV Wye Grounded	4.32	4.32	1235	116.00	8	25	0.077	39	285.9	0.00	4.32	
146	070901	MARTIN	HYBELS	HML	4.8/8.32 kV Wye Grounded	28.49	25.70	439		22					0.00	25.70	2024 Carryover
147	071002	MESICK	SPRINGVILLE	CAD	14.4 kV Delta	52.16	10.50	843		15					0.00	10.50	2024 Carryover
148	072201	WALDO	JEFFERSON	MDL	4.8/8.32 kV Wye Grounded	17.49	10.00	1114		9					10.00	0.00	2024 Carryover
149	073301	TEXAS	BASS LAKE	KAL	4.8/8.32 kV Wye Grounded	34.70	24.50	1231		14					0.00	24.50	2024 Carryover
150	073302	TEXAS	EAGLE LAKE	KAL	4.8/8.32 kV Wye Grounded	43.74	23.10	1472		16					0.00	23.10	2024 Carryover
151	074301	RED ARROW	MARKHAM	FLT	4.8/8.32 kV Wye Grounded	9.78	9.78	1207	76.00	9	23	0.034	25	123.4	9.78	0.00	
152	074604	FULTON	EASTMONT	GRE	7.2/12.47 kV Wye Grounded	11.44	11.44	770	0.00	10	23	0.000	0	67.3	0.00	11.44	
153	074903	WURTSMITH	AIR BASE	TWS	12.0 kV Delta	19.34	19.34	913	0.00	37	23	0.000	0	47.2	0.00	19.34	
154	075402	TINSMAN	FISH LAKE ROAD	FLT	4.8/8.32 kV Wye Grounded	25.31	1.70	1031		10					0.00	1.70	2024 Carryover
155	075901	REYNOLDS	REYNOLDS	JAC	14.4/24.9 kV Wye Grounded	48.60	48.60	1290	111.92	8	54	0.254	1380	26.5	0.00	48.60	
156	076002	CHEYENNE	MCDONALDS	SAG	4.8/8.32 kV Wye Grounded	12.49	11.38	1152		13					0.00	11.38	2024 Carryover
157	076602	JUDD ROAD	OTTAWA	FLT	4.8/8.32 kV Wye Grounded	12.11	12.11	433	78.77	37	19	0.358	341	35.8	0.00	12.11	
158	076605	JUDD ROAD	CARMANWOOD	FLT	4.8/8.32 kV Wye Grounded	12.06	12.06	1287	68.83	32	37	0.166	138	106.7	0.00	12.06	
159	077402	DEWEY	SEATING	GRA	7.2/12.47 kV Wye Grounded	16.09	16.09	3825	1106.75	7	27	0.083	1476	237.7	16.09	0.00	
160	078003	APPLETON	FULLER	BIG	7.2/12.47 kV Wye Grounded	11.75	11.75	1129	188.40	16	24	0.142	314	96.1	0.00	11.75	
161	078403	FOUNTAIN	BEACON	BCK	4.8/8.32 kV Wye Grounded	0.77	0.77	8	0.00	37	10	0.000	0	10.4	0.00	0.77	
162	078702	WISNER	MONROE	JAC	4.8/8.32 kV Wye Grounded	12.40	12.40	777	90.50	11	39	0.161	181	62.7	0.00	12.40	

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	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customers Impacted	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
163	078801	HONOR	INDIAN HILL	BEN	7.2/12.47 kV Wye Grounded	71.95	71.95	974	123.59	8	62	0.227	2019	13.5	0.00	71.95	
164	078901	ALTO	ALTO	GRE	4.8/8.32 kV Wye Grounded	75.48	73.00	924		20					0.00	73.00	2024 Carryover
165	079001	SEIDEL	PLAZA	SAG	4.8/8.32 kV Wye Grounded	9.57	9.57	988	21.00	9	16	0.070	14	103.2	9.57	0.00	
166	079301	RAVINE	PATTERSON	KAL	4.8/8.32 kV Wye Grounded	14.73	14.73	1302	434.50	12	35	0.091	579	88.4	0.00	14.73	
167	079302	RAVINE	RAVINE	KAL	4.8/8.32 kV Wye Grounded	30.06	1.40	1555		15					0.00	1.40	2024 Carryover
168	079702	GRAYLING	RIVER	WBR	4.8/8.32 kV Wye Grounded	35.20	35.20	1138	204.93	9	19	0.142	1025	32.3	35.20	0.00	
169	079703	GRAYLING	HOSPITAL	WBR	4.8/8.32 kV Wye Grounded	26.89	26.89	1414	115.00	10	15	0.012	38	52.6	0.00	26.89	
170	079704	GRAYLING	BEAR	WBR	4.8/8.32 kV Wye Grounded	20.61	20.51	567		13					0.00	20.51	2024 Carryover
171	080301	BOYNE MTN	BOYNE MTN	BNC	7.2/12.47 kV Wye Grounded	0.02	0.02	3	0.00	37	5	0.000	0	150.0	0.00	0.02	
172	081601	HAGADORN	WATER	LAN	4.8/8.32 kV Wye Grounded	29.36	29.36	802	203.20	10	31	0.114	677	27.3	0.00	29.36	
173	082001	FORDYCE	BAMBER	ALM	4.8/8.32 kV Wye Grounded	37.23	37.23	1291	95.67	9	32	0.054	191	34.7	37.23	0.00	
174	082202	MONTEREY	KNELLER	HML	4.8/8.32 kV Wye Grounded	16.74	16.74	116	14.43	15	24	0.139	34	6.9	0.00	16.74	
175	083501	JACKMAN	LIBERTY CORNERS	SMN	7.2/12.47 kV Wye Grounded	27.75	27.75	2115	62.29	9	47	0.288	498	76.2	0.00	27.75	
176	083503	JACKMAN	MEADOWOOD	SMN	7.2/12.47 kV Wye Grounded	21.13	21.13	1787	281.20	9	62	0.237	1406	84.6	0.00	21.13	
177	084003	HOSPITAL	KIDS CREEK	TRA	7.2/12.47 kV Wye Grounded	14.75	14.10	143		37					0.00	14.10	2024 Carryover
178	085608	FORT CUSTER	HILL-BRADY	BCK	14.4/24.9 kV Wye Grounded	7.30	7.30	30	0.00	37	11	0.000	0	4.1	0.00	7.30	
179	086001	KENTWOOD	PRINCETON	GRE	7.2/12.47 kV Wye Grounded	20.89	20.89	1831	0.00	10	12	0.000	0	87.6	0.00	20.89	
180	086802	KOLASSA	MATTESON	CLD	14.4/24.9 kV Wye Grounded	73.46	53.60	776		13					0.00	53.60	2024 Carryover
181	087704	BAGLEY	FREDERIC	BNC	14.4/24.9 kV Wye Grounded	80.30	3.90	1740		9					0.00	3.90	2024 Carryover
182	088501	BURTCH ROAD	BURTCH RD	JAC	14.4/24.9 kV Wye Grounded	88.36	88.36	1491	66.76	9	77	0.253	1491	16.9	0.00	88.36	
183	090602	HARRIET	HARRIET	FLT	4.8/8.32 kV Wye Grounded	9.22	9.22	652	18.25	37	42	0.145	24	70.7	0.00	9.22	
184	090801	OAK STREET	COOPER STREET	JAC	4.8/8.32 kV Wye Grounded	16.77	16.77	1145	102.00	9	24	0.159	272	68.3	16.77	0.00	
185	090803	OAK STREET	STATE STREET	JAC	4.8/8.32 kV Wye Grounded	3.89	3.89	657	0.00	11	20	0.000	0	168.9	0.00	3.89	
186	091603	AMPERSEE	NORTH COMMERCIAL	KAL	4.8/8.32 kV Wye Grounded	6.81	6.81	473	116.83	11	23	0.294	234	69.5	0.00	6.81	
187	091802	LOMBARD	LOMBARD	BCK	4.8/8.32 kV Wye Grounded	45.95	45.95	1351	91.66	9	55	0.210	886	29.4	45.95	0.00	
188	093202	BOON ROAD	ROUND LAKE	CAD	4.8/8.32 kV Wye Grounded	26.45	26.45	496	83.57	11	19	0.088	195	18.8	0.00	26.45	
189	093402	CALVIN	ROSEMONT	GRE	7.2/12.47 kV Wye Grounded	11.60	11.60	1380	161.67	10	16	0.086	162	119.0	0.00	11.60	
190	095202	PECK ROAD	M-91	GVL	14.4/24.9 kV Wye Grounded	44.33	44.33	728	79.50	5	100	0.436	1537	16.4	44.33	0.00	
191	095203	PECK ROAD	WISE ROAD	GVL	14.4/24.9 kV Wye Grounded	49.57	0.00	1224		8					0.00	0.00	2024 Carryover
192	096202	BEAUGRAND	MARINA	BNC	7.2/12.47 kV Wye Grounded	13.74	13.74	867	65.00	9	15	0.024	22	63.1	0.00	13.74	
193	096604	VENTURA	LOW PUMP	HML	2.4/4.16 kV Wye Grounded	1.34	1.34	1	1.00	37	13	0.498	1	0.7	0.00	1.34	
194	098203	LEFFINGWELL	RAPIDSTAN	GRA	7.2/12.47 kV Wye Grounded	5.66	5.66	454	144.75	7	20	0.236	193	80.2	5.66	0.00	
195	099601	CENTER ROAD	CENTER ROAD	FLT	4.8/8.32 kV Wye Grounded	5.72	5.72	387	390.00	37	19	0.058	130	67.7	0.00	5.72	
196	100302	NINETEEN MILE RD	INDUSTRIAL PARK	BIG	7.2/12.47 kV Wye Grounded	30.66	30.66	846	80.78	11	28	0.098	242	27.6	0.00	30.66	
197	100801	HARRIETTA	CABERFAE	CAD	14.4 kV Delta	10.40	10.40	186	118.50	5	27	0.256	316	17.9	10.40	0.00	
198	100802	HARRIETTA	BOON	CAD	14.4 kV Delta	126.06	126.06	1328	170.10	8	54	0.111	2381	10.5	0.00	126.06	
199	102202	FILLMORE	64TH STREET	GRA	7.2/12.47 kV Wye Grounded	21.30	21.30	696	188.50	10	19	0.125	503	32.7	0.00	21.30	
200	103101	COGGINS	ALMEDA	BCY	4.8/8.32 kV Wye Grounded	17.33	11.00	327		13					0.00	11.00	2024 Carryover
201	104302	MORLEY	HOLLAND	SAG	4.8/8.32 kV Wye Grounded	19.81	19.81	564	120.38	29	22	0.135	321	28.5	0.00	19.81	
202	104802	WESTERVELT	KOCHVILLE	SAG	4.8/8.32 kV Wye Grounded	9.87	9.87	64	14.57	20	21	0.236	34	6.5	0.00	9.87	
203	106601	ALDRICH	TRAVERSE	FLT	4.8/8.32 kV Wye Grounded	12.61	1.70	1006		28					0.00	1.70	2024 Carryover
204	107201	ALAMO	FISH HATCHERY	KAL	14.4/24.9 kV Wye Grounded	83.98	48.58	1537		6					0.00	48.58	2024 Carryover
205	107502	OBERLIN	BENMARK	CLR	14.4/24.9 kV Wye Grounded	170.96	114.00	2993		17					0.00	114.00	2024 Carryover
206	107702	CASS ROAD	GARFIELD	TRA	7.2/12.47 kV Wye Grounded	17.21	17.24	1085		25					0.00	17.24	2024 Carryover
207	108203	GOODALE	ROOSEVELT	BCK	4.8/8.32 kV Wye Grounded	15.23	15.23	1622	151.00	9	31	0.175	403	106.5	15.23	0.00	
208	109102	HENDERSHOT	CENTENNIAL	ADR	7.2/12.47 kV Wye Grounded	67.40	36.50	857		14					0.00	36.50	2024 Carryover
209	110801	WILLIAMS	ELY	HML	4.8/8.32 kV Wye Grounded	26.67	26.67	1059	73.18	8	66	0.687	1342	39.7	26.67	0.00	
210	111301	SHERMAN	SHERMAN	TWS	4.8/8.32 kV Wye Grounded	53.54	53.54	340		29					0.00	53.54	2024 Carryover
211	112101	ABBE	ABBE	WBR	14.4/24.9 kV Wye Grounded	130.09	130.09	1672	123.17	8	54	0.256	4106	12.9	0.00	130.09	
212	112202	KENT CITY	CASNOVIA	GRN	7.2/12.47 kV Wye Grounded	140.47	86.30	1786		22					0.00	86.30	2024 Carryover
213	112501	HUNT ROAD	TIPTON	ADR	7.2/12.47 kV Wye Grounded	0.07	0.07	0	0.00	14	2	0.000	0	0.0	0.00	0.07	
214	112502	HUNT ROAD	HOSPITAL	ADR	7.2/12.47 kV Wye Grounded	12.11	12.11	647	105.83	9	35	0.165	212	53.4	0.00	12.11	
215	113604	EMERALD	EMERALD	KAL	4.8/8.32 kV Wye Grounded	0.68	0.68	4		37					0.00	0.68	2024 Carryover
216	114301	MANTON	GILBERT	CAD	4.8/8.32 kV Wye Grounded	120.08	10.40	1000		14					0.00	10.40	2024 Carryover

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217	114403	RENTON	WATKINS	BCK	4.8/8.32 kV Wye Grounded	16.88	16.88	285	55.40	10	20	0.099	92	16.9	0.00	16.88	
218	114701	TOWN LINE	FRASER	BCY	4.8/8.32 kV Wye Grounded	20.62	20.62	458	150.60	15	20	0.081	251	22.2	0.00	20.62	
219	115005	GRAND RIVER	NEWMAN ROAD	LAN	4.8/8.32 kV Wye Grounded	2.23	2.23	31	0.00	36	5	0.000	0	13.9	0.00	2.23	
220	115102	ALABAMA	KING ROAD	SAG	4.8/8.32 kV Wye Grounded	12.89	12.89	967	128.20	10	19	0.129	214	75.0	0.00	12.89	
221	115501	MAPLE CITY	SUGAR LOAF	TRA	7.2/12.47 kV Wye Grounded	36.83	36.83	782	184.33	13	43	0.244	1659	21.2	0.00	36.83	
222	115502	MAPLE CITY	CEDAR	TRA	7.2/12.47 kV Wye Grounded	115.67	115.67	1388	74.67	12	90	0.202	1742	12.0	0.00	115.67	
223	115902	BALLENGER	SALISBURY	FLT	4.8/8.32 kV Wye Grounded	6.13	6.13	1026	44.00	11	43	0.326	88	167.4	0.00	6.13	
224	117902	SKYLARK	RIVERBEND	FLT	4.8/8.32 kV Wye Grounded	23.22	2.90	1990		9					2.90	0.00	2024 Carryover
225	119102	SQUIRES	ALLEN	CLD	4.8/8.32 kV Wye Grounded	58.65	58.65	661	47.22	10	39	0.131	362	11.3	0.00	58.65	
226	120201	TUCKER	MACKEY	FLT	4.8/8.32 kV Wye Grounded	32.65	32.65	741	76.88	22	44	0.163	410	22.7	0.00	32.65	
227	122401	PETTIS ROAD	HONEY CREEK	GRN	14.4/24.9 kV Wye Grounded	61.17	61.17	842	67.11	6	81	0.332	1365	13.8	0.00	61.17	
228	123101	BIG PRAIRIE	BIG BEND	BIG	4.8/8.32 kV Wye Grounded	21.09	21.09	362	46.68	9	43	0.490	482	17.2	21.09	0.00	
229	123602	BAILEY	CHERRY	FRE	4.8/8.32 kV Wye Grounded	28.47	28.47	386	36.71	27	25	0.246	257	13.6	0.00	28.47	
230	124205	BRETON	TOWERS	GRA	7.2/12.47 kV Wye Grounded	10.46	10.46	1277	58.00	36	15	0.064	39	122.1	0.00	10.46	
231	124501	CEDAR LAKE	KINGS CORNER	TWS	14.4/24.9 kV Wye Grounded	91.45	19.80	1935		15					0.00	19.80	2024 Carryover
232	125203	UPTON	SIMMONS	LAN	4.8/8.32 kV Wye Grounded	25.40	25.40	1259	85.50	37	45	0.262	570	49.6	0.00	25.40	
233	127301	WHITTEMORE	M-65	TWS	14.4/24.9 kV Wye Grounded	136.10	136.10	1649	66.06	8	35	0.176	1585	12.1	0.00	136.10	
234	127701	LEVELY	ALLBRIGHT	MDL	14.4/24.9 kV Wye Grounded	88.25	88.25	2911	171.33	7	39	0.162	2456	33.0	0.00	88.25	
235	127702	LEVELY	STURGEON	MDL	14.4/24.9 kV Wye Grounded	111.50	57.57	2043		6					0.00	57.57	2024 Carryover
236	128802	BENNETT	JOLLY ROAD	LAN	4.8/8.32 kV Wye Grounded	15.97	15.97	1243	315.89	25	21	0.188	948	77.8	0.00	15.97	
237	129601	BLACKMAN	SANDSTONE	JAC	14.4/24.9 kV Wye Grounded	53.64	53.64	2898	324.76	7	39	0.205	3572	54.0	0.00	53.64	
238	129802	VANDERBILT	WOLVERINE	BNC	13.2 kV Delta	74.48	74.48	1073	143.40	5	46	0.215	2294	14.4	74.48	0.00	
239	131402	BELKNAP	TODD FARM	HML	4.8/8.32 kV Wye Grounded	37.52	37.52	374	27.45	37	62	0.338	348	10.0	0.00	37.52	
240	132202	BROGAN	SOUTH	HST	4.8/8.32 kV Wye Grounded	28.65	28.65	263	46.33	26	33	0.209	278	9.2	0.00	28.65	
241	133501	TALLMAN	WACOUSTA	LAN	14.4/24.9 kV Wye Grounded	93.29	2.60	1475		14					0.00	2.60	2024 Carryover
242	133904	WATKINS	MINGES CREEK	BCK	4.8/8.32 kV Wye Grounded	10.93	10.93	1640	212.25	23	13	0.122	283	150.0	0.00	10.93	
243	134002	ALDER CREEK	EAST LEROY	BCK	14.4/24.9 kV Wye Grounded	103.11	42.20	1184		9					0.00	42.20	2024 Carryover
244	135601	CANNONSBURG	WEST CANNON	GRN	4.8/8.32 kV Wye Grounded	55.18	55.18	1146	93.35	26	95	0.447	2303	20.8	0.00	55.18	
245	135901	KIPP ROAD	M-36	LAN	14.4/24.9 kV Wye Grounded	101.37	101.37	795	194.57	28	60	0.122	2400	7.8	0.00	101.37	
246	136601	M.A.E.	LINCOLN ROAD	SMN	7.2/12.47 kV Wye Grounded	13.28	13.28	1360	92.50	9	28	0.151	185	102.4	0.00	13.28	
247	137101	CLYDE ROAD	GLENN ROAD	GVL	14.4/24.9 kV Wye Grounded	57.67	57.67	1129	158.00	6	50	0.197	1791	19.6	0.00	57.67	
248	137102	CLYDE ROAD	STATE ROAD	GVL	14.4/24.9 kV Wye Grounded	34.85	34.85	1076	90.44	19	40	0.172	543	30.9	0.00	34.85	
249	137201	BALZER	SANDERS	LAN	14.4/24.9 kV Wye Grounded	59.42	59.42	816	127.00	20	55	0.151	1143	13.7	0.00	59.42	
250	137302	TWILIGHT	GULL ROAD	KAL	4.8/8.32 kV Wye Grounded	51.68	1.90	2667		10					0.00	1.90	2024 Carryover
251	137801	SANDERSON	COUNTY FARM	GVL	14.4/24.9 kV Wye Grounded	30.50	30.50	327	98.05	9	35	0.208	621	10.7	0.00	30.50	
252	137805	SANDERSON	KENT RD	GVL	14.4/24.9 kV Wye Grounded	12.09	0.00	988		37					0.00	0.00	2024 Carryover
253	138303	MILL GROVE	DUMONT	HML	14.4/24.9 kV Wye Grounded	87.43	45.20	1096		6					0.00	45.20	2024 Carryover
254	139501	WARNER	MILO	KAL	14.4/24.9 kV Wye Grounded	122.17	122.17	1836	169.85	5	88	0.218	4529	15.0	122.17	0.00	
255	140201	SIMMONS	DAM ROAD	WBR	14.4/24.9 kV Wye Grounded	147.03	88.40	1688		19					0.00	88.40	2024 Carryover
256	140701	SILVER LAKE	SECOR	TRA	7.2/12.47 kV Wye Grounded	46.67	46.67	1300	65.05	14	53	0.300	911	27.9	0.00	46.67	
257	140703	SILVER LAKE	TWIN LAKE	TRA	7.2/12.47 kV Wye Grounded	30.59	30.59	1114	92.58	14	31	0.131	370	36.4	0.00	30.59	
258	141802	HACKETT	DICE ROAD	SAG	4.8/8.32 kV Wye Grounded	44.59	22.00	1144		10					0.00	22.00	2024 Carryover
259	142701	IRISH ROAD	BELLE MEADE	FLT	14.4/24.9 kV Wye Grounded	21.77	21.77	1197	187.36	23	33	0.214	874	55.0	0.00	21.77	
260	142703	IRISH ROAD	CRYSTALWOOD	FLT	14.4/24.9 kV Wye Grounded	47.30	47.30	2937	151.45	37	42	0.155	1111	62.1	0.00	47.30	
261	145101	NOBLE	DUBY	TWS	14.4/24.9 kV Wye Grounded	25.64	25.64	542	111.71	8	16	0.091	261	21.1	0.00	25.64	
262	147801	JAMES SAVAGE	WASHINGTON	MDL	4.8/8.32 kV Wye Grounded	11.78	11.78	1027	90.00	13	16	0.057	60	87.2	0.00	11.78	
263	148301	MANNSIDING	CEDAR	CLR	14.4/24.9 kV Wye Grounded	65.59	65.59	1675	258.09	8	62	0.173	2925	25.5	0.00	65.59	
264	148602	DEER LAKE	BALL AVENUE	CLR	4.8/8.32 kV Wye Grounded	45.05	45.05	1473	158.15	10	62	0.296	2109	32.7	0.00	45.05	
265	149802	WEST FENTON	NORTH ROAD	FLT	4.8/8.32 kV Wye Grounded	12.81	12.81	915	340.29	37	23	0.182	794	71.4	0.00	12.81	
266	150702	EAST JACKSON	DONNELY	JAC	4.8/8.32 kV Wye Grounded	25.95	25.95	1388	177.58	11	27	0.154	710	53.5	0.00	25.95	
267	151102	LELAND	LELAND	TRA	7.2/12.47 kV Wye Grounded	56.45	56.45	1304	145.69	15	86	0.325	2671	23.1	0.00	56.45	
268	152703	COIT AVENUE	RIFLE RANGE	GRN	7.2/12.47 kV Wye Grounded	6.16	6.16	504	107.60	8	27	0.541	359	81.8	0.00	6.16	
269	153002	HUBBARDSTON ROAD	STONEY CREEK	GVL	14.4/24.9 kV Wye Grounded	21.15	21.15	465	38.17	37	28	0.189	153	22.0	0.00	21.15	
270	154202	SPICEBUSH	LACOTA	KAL	14.4 kV Delta	38.40	38.40	535	54.55	6	54	0.191	400	13.9	0.00	38.40	

Line No.	(a) Description	(b) Feeder ID	(c) Substation	(d) Circuit	(e) HQ	(f) Voltage	(g) Circuit Miles	(h) Work Plan Miles	(i) Circuit Customers	(j) Average Outages per Incident	(k) Years Since Last Cleared	(l) Relative Risk Score (0-100)	(m) 3-Year Weighted Average Incidents per Mile	(n) Customers Impacted	(o) Customer Density per Mile	(p) On Cycle Miles	Backlog Miles	Notes
271		155801	SCHOOL ROAD	MOROCCO	SMN	7.2/12.47 kV Wye Grounded	48.73	48.73	1065	55.17	7	54	0.239	644	21.9	48.73	0.00	
272		157002	MILBOURNE	PASADENA	FLT	4.8/8.32 kV Wye Grounded	14.68	14.68	1288	376.45	15	63	0.250	1380	87.7	0.00	14.68	
273		158201	RYNO	MORENCI	WBR	14.4/24.9 kV Wye Grounded	70.26	70.26	1720	158.24	7	50	0.100	1108	24.5	0.00	70.26	
274		158901	BUCHANAN	SANDY SHORES	HML	4.8/8.32 kV Wye Grounded	21.96	21.96	754	115.00	9	39	0.228	575	34.3	21.96	0.00	
275		159702	STANWOOD	RIVERSWAY	BIG	7.2/12.47 kV Wye Grounded	52.39	52.39	1265	105.83	10	50	0.185	1023	24.1	0.00	52.39	
276		160402	RATIGAN	MURRAY LAKE	GRN	14.4/24.9 kV Wye Grounded	43.61	24.90	855		37					0.00	24.90	2024 Carryover
277		162801	FISH LAKE	SEVEN LAKES	FLT	4.8/8.32 kV Wye Grounded	29.78	29.78	911	198.73	10	46	0.291	1722	30.6	0.00	29.78	
278		163703	WILLIS ROAD	LIST ROAD	JAC	14.4/24.9 kV Wye Grounded	50.07	50.02	836		6					0.00	50.02	2024 Carryover
279		163802	DOBSON ROAD	HALF MOON	CLD	4.8/8.32 kV Wye Grounded	22.96	3.00	248		10					0.00	3.00	2024 Carryover
280		165901	MOSEL	PITCHER	KAL	4.8/8.32 kV Wye Grounded	6.03	6.03	613	134.00	37	16	0.055	45	101.7	0.00	6.03	
281		167301	THORNTON	WEST RIVER RD	MDL	4.8/8.32 kV Wye Grounded	32.19	32.19	1211	119.00	9	44	0.311	1190	37.6	32.19	0.00	
282		168601	STURGEON	SAGINAW ROAD	MDL	4.8/8.32 kV Wye Grounded	29.38	29.38	2112	49.20	37	19	0.057	82	71.9	0.00	29.38	
283		168903	SAND CREEK	M-34	ADR	7.2/12.47 kV Wye Grounded	5.18	5.18	176	0.00	15	2	0.000	0	34.0	0.00	5.18	

EXHIBIT A-174 (SES-5)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Forestry Operations
($000)

Case No.: U-21870
Exhibit No.: A-175 (SES-6)
Page: 1 of 2
Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	**Forestry Operations Administration and Work Planning - baseline**	**7,027**	**11,064**
	Labor	3,262	5,583
	Material	0	0
	Contractor	3,028	4,038
	Non-Labor Overhead	736	1,444
	Non-Labor Other	0	0
2	**Line Clearing Contractor Costs - baseline**	**103,198**	**175,620**
	Labor	0	0
	Material	0	0
	Contractor	103,198	175,620
	Non-Labor Overhead	0	0
	Non-Labor Other	0	0
3	**Total Forestry Operations O&M Expenses**	**110,225**	**186,684**
	Labor	3,262	5,583
	Material	0	0
	Contractor	106,226	179,657
	Non-Labor Overhead	736	1,444
	Non-Labor Other	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Forestry Operations
($000)

Case No.: U-21870
Exhibit No.: A-175 (SES-6)
Page: 2 of 2
Witness: SEStewart
Date: June 2025

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2024	(c) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2024	(d) Merit & Inflation 12 Mos Ending 12/31/2025	(e) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2025	(f) Merit & Inflation 12 Mos Ending 12/31/2026	(g) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2026	(h) Merit & Inflation 4 Mos Ending 4/30/2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending 4/30/2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Forestry Operations Administration and Work Planning - baseline**	**7,027**	**7,027**	**0**	**8,345**	**0**	**9,260**	0	**4,038**	11,064
	Labor	3,262	3,262	0	4,328	0	4,831	0	2,321	5,583
	Material	0	0	0	0	0	0	0	0	0
	Contractor	3,028	3,028	0	2,836	0	3,070	0	1,009	4,038
	Non-Labor Overhead	736	736	0	1,181	0	1,359	0	708	1,444
	Non-Labor Other	0	0	0	0	0	0	0	0	0
2	**Line Clearing Contractor Costs - baseline**	**103,198**	**103,198**	**0**	**117,062**	**0**	**155,693**	0	**72,422**	175,620
	Labor	0	0	0	0	0	0	0	0	0
	Material	0	0	0	0	0	0	0	0	0
	Contractor	103,198	103,198	0	117,062	0	155,693	0	72,422	175,620
	Non-Labor Overhead	0	0	0	0	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0	0	0	0	0
3	**Total Forestry Operations O&M Expenses**	**110,225**	**110,225**	**0**	**125,407**	**0**	**164,953**	**0**	**76,459**	**186,684**
	Labor	3,262	3,262	0	4,328	0	4,831	0	2,321	5,583
	Material	0	0	0	0	0	0	0	0	0
	Contractor	106,226	106,226	0	119,898	0	158,763	0	73,431	179,657
	Non-Labor Overhead	736	736	0	1,181	0	1,359	0	708	1,444
	Non-Labor Other	0	0	0	0	0	0	0	0	0

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly			
Number of months in the period	12	12	4
Pro-rated inflation rate	0.0%	0.0%	0.0%

Consumers Energy
Count on Us

September 3, 2024

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

RE: Case No. U-20697 – In the matter of the application of Consumers Energy Company for Authority to increase its rates for the generation and distribution of electricity and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Line Clearing Program Formal Optimization Analysis of Line Clearing Cycles.**

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

Sincerely,

Bret Totoraitis
Digitally signed by Bret A. Totoraitis
Date: 2024.09.03 14:39:20 -04'00'

Bret A. Totoraitis
Phone: 517-788-0835
Email: bret.totoraitis@cmsenergy.com

cc: Hon. Sally L. Wallace, Administrative Law Judge
Parties per Attachment 1 to Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

CONSUMERS ENERGY COMPANY'S

LINE CLEARING PROGRAM

FORMAL OPTIMIZATION ANALYSIS OF LINE CLEARING CYCLES

Background

The Michigan Public Service Commission ("MPSC") directed Consumers Energy Company ("Consumers Energy" or the "Company") to perform a formal optimization analysis of line clearing cycles in its final Order in Case No. U-21389 ("the Order"), as follows:

> The Commission further directs Consumers to perform a formal optimization analysis of line clearing cycles that accounts for customer costs of outages, the costs of service restoration, and the costs of line clearing, including an evaluation of shorter clearing cycles, and further agrees with MNSC that this analysis "should look with particularity to the customer costs and restoration costs associated with tree-caused outages and not at average values acrost all outages." [MPSC Case No. U-21389, March 1, 2024 Order, pages 163-164.]

Per the Order, this report covers a formal optimization analysis of line clearing cycles that accounts for customer costs of outages, the costs of service restoration, and the costs of line clearing. The report is separated into 11 sections as described below:

Section 1: Overview

Section 2: Methodology of Estimating Tree-Caused Incidents

Section 3: Methodology of Estimating Customer Costs of LVD Tree-Caused Outages

Section 4: Methodology of Estimating Costs of LVD Tree-Caused Service Restoration

Section 5: Methodology of Estimating Costs of Line Clearing

Section 6: Total Costs per Cycle Length

Section 7: Methodology of Residential and Non-Residential Costs Allocation

Section 8: Residential Costs Allocation per Cycle Length

Section 9: Conclusion of Formal Optimization Analysis of Line Clearing Cycles

Section 10: Further Considerations for Non-Residential Customers

Section 11: Recommendation

Section 1 – Overview

Line clearing cycles are measured by years and reflect the amount of time that passes between line clearing on a circuit. The Company is on its glidepath to achieving a seven-year effective cycle for its Low Voltage Distribution ("LVD") system, which is the scope of this formal optimization analysis of line clearing cycles. In its rate cases, the Company has outlined the -seven-year effective cycle as the most cost-beneficial approach to optimize system performance at current system conditions. There are three primary components of the seven-year effective cycle analysis:

1. All-weather (including Major Event Days ("MEDs")) LVD primary incidents,
2. Contractor cost per mile, and
3. Cycle contractor cost per incident, which is the division of projected line clearing contractor expense at each cycle length by the projected incidents expected at the cycle length.

The Order directed the Company to take different measurements into account and to evaluate shorter cycles. Accordingly, this analysis evaluates several fixed, time-based cycles – cycles between nine and four years in length – across LVD voltage classes and includes three main components for consideration:

1. Customer costs of tree-caused outages,
2. Costs of tree-caused service restoration, and
3. Costs of line clearing.

The customer costs of outages are defined as "economic losses that customers experience when [electric] service is interrupted – usually obtained by surveying representative samples of

customers about the economic losses they experience as a result of electric service interruptions."[1] In this formal optimization analysis of line clearing cycles, estimated interruption costs are utilized from Ernest Orlando Lawrence Berkeley National Laboratory: Estimated Value of Service Reliability for Electric Utility Customers in the United States. Costs are separated by customer type: residential customers, small commercial and industrial ("C&I") customers, and medium and large C&I customers. Small C&I customers are defined as non-residential customers consuming less than 50 megawatt hours ("MWh") per year, and medium and large C&I customers are defined as non-residential customers consuming more than 50 MWh per year. The annual customer costs of outages are estimated per cycle length by customer type.

The costs of tree-caused service restoration are the annual estimated costs per cycle length given the projected number of tree-caused outage incidents including MEDs and estimated cost per tree-caused outage incident. The estimated cost per tree-caused outage incident is illustrated in the equation below and expanded upon in Section 4.

$$Cost\ per\ Tree\ Caused\ Outage\ Incident = \frac{((Costs\ Associated\ with\ Field\ Work\ Orders\ Associated\ with\ Tree\ Caused\ Outage\ Incidents)+(A\ Proportion\ of\ Overhead\ Costs))}{Count\ of\ Tree\ Caused\ Outage\ Incidents}$$

The costs of line clearing include all annual estimated expenses of the LVD portion of the program at varying cycle lengths, including contractor costs, salaries, and expenses. As directed in the Order, the Company considers how higher contractor costs, incurred when the Company outsources non-local crews to execute a larger volume of work, impact overall line clearing costs.

[1] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, page xv (last visited August 28, 2024), https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf.

Line clearing costs also include an estimated LVD line clearing administrative cost to manage the program at varying cycle lengths. Line clearing administrative costs capture the internal expenses of the Company's Forestry Operations Department, which administers the contracts and oversees the performance of the Company's line clearing contractors. These costs also include the contract foresters and work planners that plan the work and interact with customers. As cycle lengths (time between line clearing) decrease, annual line clearing work volume increases, and more resources are needed to execute the increased volume – both in the form of line clearing crews and supporting staff to plan the work, interact with customers, and manage the program.

While there is some overlap, this formal optimization analysis of line clearing cycles and the analysis that resulted in the seven-year effective cycle, as described in Section 1, differ. Both analyses generally consider differing measurements for optimization, but this analysis includes measurements that have not been used previously, such as customer costs of outages. Both analyses include line clearing costs, but this analysis includes more than just contractor costs and reflects estimated costs for the LVD portion of the program. Both analyses estimate the annual number of tree-caused outage incidents including MEDs at varying cycle lengths; however, this analysis includes all LVD areas of fault[2] to quantify the annual LVD system reliability to ensure all outages are captured (and can be reflected in the annual cost of customer tree-caused outages and annual cost of tree-caused service restoration). For comparison, the seven-year effective cycle analysis includes primary incidents only.

This formal optimization analysis assumes: (i) steady-state maintenance of each cycle length analyzed; in other words, this analysis assumes the cycle has already been achieved for each cycle length scenario and there are zero backlog miles that have not been cleared within that cycle

[2] Primary, secondary, and service point.

length; (ii) line miles are cleared to current LVD clearing specification; and (iii) the cycle lengths are fixed, time-based cycles clearing all LVD voltages at the same frequency.[3] Additionally, the framework of this analysis utilizes the timeframe of one year using costs inflated to 2024. Line clearing costs, tree-caused outage rates, and associated tree-caused service restoration costs and customer costs of tree-caused outages reflect projected annual amounts once the corresponding cycle length has been achieved.

At a higher level, the goal of this formal optimization analysis is to pinpoint the optimal line clearing cycle length that maximizes customer benefits at the lowest possible cost to customers. These customer costs are the sum of tree-caused outage costs, tree-caused service restoration costs, and line clearing costs. Considering costs across all customer types (residential and non-residential) together in the analysis leads to a four-year optimal cycle length. But while this may be the optimal line clearing cycle when considering *all costs*, it is not the optimal cycle for *all customers*. The Company reached this conclusion after it refined its analysis by allocating and separately evaluating the annual line clearing and tree-caused service restoration costs that would be collected through rates from residential and non-residential customers.

Isolating the impact on residential customers in the analysis leads to a longer optimized cycle: a cycle length between six and seven years. Residential customers bear the brunt of the line clearing and service restoration costs through rates, while non-residential customers receive a disproportionate share of the benefits. It would not be fair or equitable to ask residential customers to pay more to further shorten line clearing cycles that disproportionally benefit non-residential

[3] It should be noted that fixed, time-based cycles do not allow for risk-based prioritization based on circuit attributes that contribute to reliability performance, such as voltage. The seven-year effective cycle strategy considers circuit performance by voltage variation.

customers. For this reason, the Company recommends the optimal cycle for residential customers as the optimal cycle length for the Commission's consideration.

Section 2 – Methodology of Estimating Tree-Caused Incidents

This formal optimization analysis of line clearing cycles is rooted in the annual projected number of tree-caused incidents including MEDs given a clearing cycle length for LVD circuits for all LVD areas of fault. To obtain this number for various cycle lengths, Company data was used to get a measurement of LVD circuit performance before clearing to an average of the full cycle length after clearing for various cycles. The framework of this portion of the analysis utilizes circuits with a year since last cleared ("YSLC") from 2017 to 2022, as shown in Table 1, to ensure the benefits of hazard tree removal (which began in 2016) are captured and have at least one full calendar year post-clearing.

Table 1 – Framework to Estimating Tree-Caused Incidents

YSLC-1	YSLC	YSLC +1	YSLC +2	YSLC +3	YSLC +4	YSLC +5	YSLC +6
2016	2017	2018	2019	2020	2021	2022	2023
2017	2018	2019	2020	2021	2022	2023	
2018	2019	2020	2021	2022	2023		
2019	2020	2021	2022	2023			
2020	2021	2022	2023				
2021	2022	2023					

Circuits that had other subprogram work completed on them in the years after they were fully cleared were excluded. The resulting sample is of significant size: more than 700 circuits comprising about 23,000 primary miles (38% of the Company's primary miles). As the LVD system becomes more on-cycle, the sample size becomes more representative.

Tree-caused outage incidents including MEDs for all LVD areas of fault are summed for the calendar year before clearing and averaged for the years after clearing for each YSLC to get a percent improvement pre- to post-clearing, comparing the year before clearing to the average

annual performance over the cycle length after clearing. For example, for a five-year cycle, circuits that were last cleared in 2017, 2018, and 2019 are used to calculate the percentage improvement as they all have four full calendar years post-clearing that represents the time between clearings for a five-year cycle. This approach limits the impact of weather patterns of any one year on the overall trendline. Additionally, this approach compares circuits to themselves over time, rather than comparing circuits to each other which would introduce inter-circuit variation. This methodology was repeated across multiple cycle lengths, resulting in a percentage reduction in tree-caused incidents including MEDs pre- to post-clearing per cycle length.[4] This trend[5] was utilized to estimate the percentage reduction in tree-caused incidents pre- to post-clearing for other cycle lengths, and then this reduction was applied to a five-year average of tree-caused outage incidents including MEDs to get the resulting number of annual LVD tree-caused outage incidents by cycle length.

Section 3 – Methodology of Estimating Customer Costs of LVD Tree-Caused Outages

To incorporate the customer costs of outages into this optimization analysis, interruption costs are utilized from Ernest Orlando Lawrence Berkeley National Laboratory, based on 2008 data: Estimated Value of Service Reliability for Electric Utility Customers in the United States. Two adjustments were made to figures in the paper to fit this optimization analysis: (i) mean interruption cost per event by customer type was translated to cost per minute of interruption to be able to account for faster average restoration in the existence of lesser outage incidents. This was accomplished by taking the 4-hour cost per interruption by customer type and dividing it by

[4] These percentages were then graphed and a polynomial line of best fit applied; the resulting high R-squared value indicates the regression model has a strong fit.
[5] Polynomial regression equation.

240 minutes to get the cost per interruption minute; and (ii) cost per minute of interruption was inflated to transform these 2008 figures to current time by applying an inflation factor utilizing Consumer Price Index (2008 to 2024).[6] The resulting customer cost per interruption minute is in Table 2.

Table 2 – 2024 Cost of Interruption by Customer Type

Customer Type	Cost of Interruption ($ per min)
Residential	$0.04
Small C&I	$14.79
Medium and Large C&I	$235.10

Annual tree-caused incidents per cycle length were translated into customer minutes by calculating tree-caused System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI") utilizing recent Company averages per incident. First, SAIFI is estimated using the two-year average customers interrupted per tree-caused incident from 2022-2023 to reflect most recent restoration tactics. Second, CAIDI by cycle length is estimated using a linear regression relationship between the number of annual tree-caused incidents and overall tree-caused CAIDI. Third, tree-caused SAIDI is estimated by multiplying tree-caused CAIDI and tree-caused SAIFI per cycle length. Total annual customer minutes result by multiplying estimated tree-caused SAIDI per cycle length by total customers served.

Estimated customer outage minutes per cycle length are allocated to customer types of residential, small C&I, and medium and large C&I customers by utilizing Company data of percentage of outage minutes that each customer type experienced in 2023. This percent breakdown is shown in Table 3.

[6] https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202402.pdf

Table 3 – 2023 Customer Outage Minutes by Customer Type

Customer Type	Percentage of Total Customer Outage Minutes
Residential	90.18%
Small C&I	7.09%
Medium and Large C&I	2.73%

The percentage of total customer outage minutes in Table 3 utilizes an approximation of the small C&I and medium and large C&I split, as Consumers Energy does not categorize customers in the same way as the analysis in Ernest Orlando Lawrence Berkeley National Laboratory: Estimated Value of Service Reliability for Electric Utility Customers in the United States.[7] Data in Table 3 was estimated using a sample size of 300 non-residential usage points and categorizing them based on the MWh consumption of each over the sample year. To calculate the total customer cost of tree-caused outages per cycle length, customer minutes are multiplied by the cost per minute of interruption for the respective customer types.

Section 4 – Methodology of Estimating Costs of LVD Tree-Caused Service Restoration

In Case No. U-21585, Exhibit A-48 (PLB-2), line 7, the Company uses an average cost per outage incident, which is calculated by dividing a five-year sum of service restoration Operations and Maintenance ("O&M") expense by the total outage incidents over the same period, resulting in a five-year average O&M cost per outage incident across all outage cause codes.[8] Case No. U-21585, Exhibit A-48 (PLB-2) is attached to this report as Attachment 2. In the Order describing this formal optimization analysis of line clearing cycles, the Commission directed the Company to

[7] See generally, *Estimated Value of Service Reliability, supra*.
[8] Examples of outage cause codes include, among others, "Animal," "Car/Pole Accident," "Equipment Failure," "Trees," and "Weather."

use service restoration costs associated with tree-caused outage incidents to calculate costs of tree-caused service restoration, not an average cost per outage incident across all outage cause codes. The Company previously used an average cost per outage incident across all outage causes because cost data is not segmented in a way that allows the Company always to correlate costs with the incidents that caused them. Service restoration costs are collected in individual field work orders or in headquarter and/or statewide storm orders (e.g., overhead costs of carrying out an organization's functions, processes, or responsibilities not specifically carried out through field work orders), and it is because of the headquarter and/or statewide storm orders that it is not possible to directly correlate all service restoration costs to specific outage incidents.

To obtain an estimated service restoration cost per tree-caused outage incident, the Company first identified 2023 costs tied directly to field work orders associated with outages that had a tree-caused cause code. Second, overhead costs (i.e., costs not directly associated with an outage) are captured and allocated out proportionally to the outages that are tree-caused. Both capital and O&M costs were allocated in this manner to estimate a total service restoration cost for all tree-caused outage incidents in 2023. Third, this total cost was divided by the total tree-caused outage incidents for this year to determine a cost per tree-caused outage incident.

This calculation results in an estimated O&M service restoration cost per tree-caused outage incident in 2023 of $2,658 and an estimated capital cost per tree-caused outage incident in 2023 of $923. For the optimization analysis, an inflation factor of 3%[9] was then applied to estimate the cost per tree-caused outage incident for the current year, and the resulting figure of $3,688 per tree-caused outage incident was applied to the nine-year cycle. As cycle length reduces, the Company assumed that the service restoration cost per tree-caused outage incident decreases with

[9] S&P Global Market Intelligence: *US Economic Outlook August 2024*

an overall reduction in tree-caused outage incidents (fewer outages translate into lower overall service restoration costs) at the same rate as the historical trend for all cause codes, adjusted for inflation. It must be noted that this assumption is based historical trends, and this trend may change in the future with new and more aggressive restoration tactics to satisfy enhanced Service Quality and Reliability Standards.[10] These opportunities and other future business dynamics may influence trends that affect the assumptions in this analysis.

To calculate the annual costs of tree-caused service restoration per cycle length, service restoration costs per tree-caused outage incident are multiplied by the estimated annual cycle incidents that were, as described above, based on historical data.

Section 5 – Methodology of Estimating Costs of Line Clearing

Annual costs of line clearing are included in this formal optimization analysis of line clearing cycles. The costs of line clearing include estimated costs of the LVD portion of the Line Clearing Program at varying cycle lengths, including contractor costs, salaries, and expenses.

To estimate contractor costs at various cycle lengths, 2023 actual contractor costs (excluding brush control [herbicide treatments]) and corresponding miles were analyzed by YSLC.[11] The sample size of this portion of the analysis is 3,300 miles of lines cleared in 2023 that had been last cleared 5 to 20 years earlier. This trend[12] was then utilized to estimate the contractor cost per mile for various cycle lengths, applying an annual adjustment inflation factor per line clearing contracts of 2% from 2023 to 2024 and a 5% increase due to new contract executions, as

[10] Rule 22, Mich Admin Code, R 460.722, was amended in 2023 to require 90% of customers be restored in 24 hours for gray sky events and 90% of customers to be restored in 48 hours for catastrophic events. Further, Rule 23, Mich Admin Code, R 460.723, was amended in 2023 to decrease the amount of time an electric utility has to relieve a "first responder guarded downed wire."
[11] Costs per mile by YSLC were graphed and a polynomial line of best fit applied.
[12] Polynomial regression equation.

stated in Case No. U-21585 Company witness Pamela L. Bolden's direct testimony page 35, lines 12-17. It is assumed that the Company can acquire 410 LVD crews at an in-state labor rate, and any crewing needs above 410 would be at an elevated cost to consider the expense of added per diems for outsourced crews. Additionally, it is assumed in this analysis that: (i) the demand and brush control portion of the program costs remain stagnant over various cycle lengths as the need for demand clearing declines and offsets increases in the brushing miles; and (ii) all O&M line clearing miles are within the subprogram of full-circuit clearing (smaller subprograms[13] are absorbed into the full-circuit clearing subprogram).

To estimate the annual cost of distribution salaries and distribution contract planning by cycle length, this analysis assumes a current staffing baseline of 54 Full-Time Equivalent ("FTE") employees. It adds one FTE for every $2 million increase in contractor spend at an average FTE cost of $87,000 annually. To estimate the cost of distribution expenses by cycle length, the distribution expenses projected in Case No. U-21585 Exhibit A-47 (PLB-1), line 22, column (l), for 2024 of $1.066 million are assumed to increase proportionally to the increase in salaries. Case No. U-21585, Exhibit A-47 (PLB-1) is attached to this report as Attachment 1.

In this formal optimization analysis, the costs of line clearing reflect a steady-state annual cost to maintain the cycle. In other words, for each cycle, the costs per mile assume the LVD system is already on this cycle and there are no backlog miles that have gone longer than this cycle length between clearing. It is important to note that current state system conditions reflect a higher cost per mile as circuits are being brought to the seven-year effective cycle from backlog status. In the event of a program "surge" to expedite reaching shorter cycles, program costs would reflect higher costs per mile to match current system conditions and the annual LVD line clearing costs

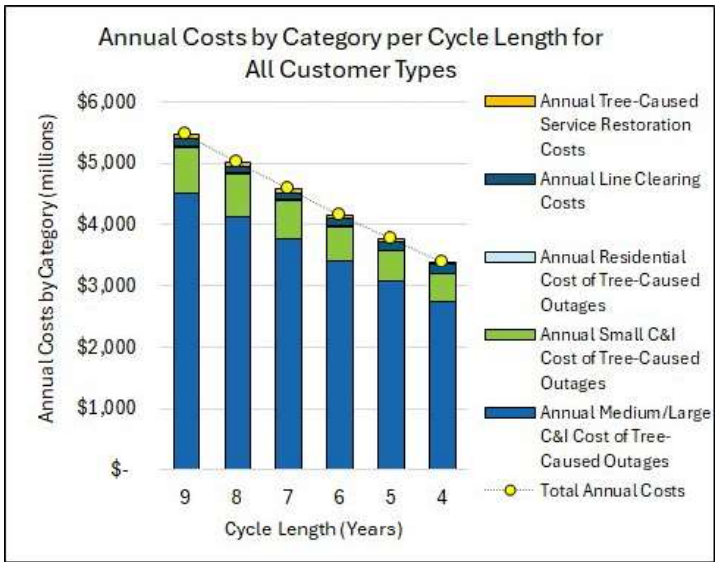
[13] First zone, repetitive outage, Customers Experiencing Multiple Interruptions (CEMI), Load Concentration Point (LCP) zonal clearing.

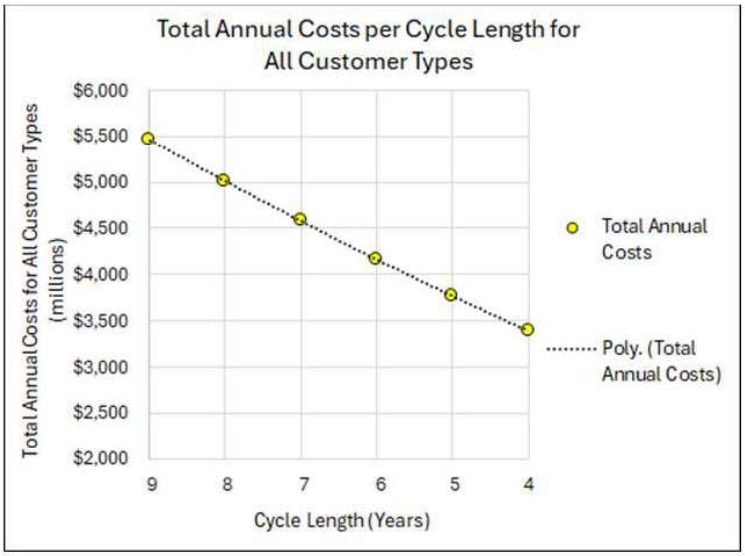
would be higher for the duration of the "surge." Over time, as the LVD system becomes on-cycle, costs per mile would reduce and "surge" costs would come down gradually to a steady-state annual cost.

Section 6 – Total Costs per Cycle Length

This formal optimization analysis of line clearing cycles considers the customer costs of tree-caused outages, the costs of tree-caused service restoration, and the costs of line clearing over cycle lengths from nine to four years. The annual costs of tree-caused outages are associated with the customer types of residential, small C&I, and medium and large C&I. The costs of tree-caused service restoration and the costs of line clearing reflect annual estimated costs across the LVD system. This optimization analysis first views all customers through the same optimization lens, combining total costs by cycle length. The cycle length option with the lowest annual costs is technically optimal. Figure 1 illustrates these combined annual costs (customer costs of tree-caused outages, costs of tree-caused service restoration, and costs of line clearing) by cycle length for all customer types. The two graphs in Figure 1 show the same data in two ways: (i) a stacked bar chart to show annual cost breakdown by category per cycle length; and (ii) a dot graph scaled to the range of total annual costs per cycle length. Data displayed in Figure 1 is in Attachment 3, which is attached to this report.

Figure 1 – Annual Costs per Cycle Length for All Customer Types





An optimization analysis that includes all customer types combined is disproportionately driven by the non-residential customer costs of outages. The result of this combined optimization analysis points to a 4-year cycle length as optimal out of these choices, benefiting non-residential (small C&I and medium and large C&I) customers the most. However, considering that residential customers bear the majority of the line clearing and service restoration costs through rates, the Company refined this analysis by allocating these costs to each customer type.

Section 7 – Methodology of Residential and Non-Residential Costs Allocation

To estimate allocation of tree-caused service restoration and line clearing costs to residential and non-residential customers by cycle length analyzed in this formal optimization analysis, a sub-analysis was conducted to estimate the costs that would be collected through rates by customer type. This sub-analysis assumes a one-time capital investment per incident to calculate the impact to customers utilizing ratemaking principles. The total revenue requirement

related to capital spending was calculated for service restoration costs, which resulted in approximately 11.3%[14] included in rates for recovery in a year. The allocation for line clearing and service restoration costs to residential and non-residential customers through rates is in Table 4.

Table 4 – Cost Allocation Through Rates, Percent by Customer Type

Cost Type	Residential	Non-Residential
Forestry O&M	65.8%	34.2%
Service Restoration O&M	65.8%	34.2%
Service Restoration Capital	61.5%	38.5%

The percent allocation to residential and non-residential customers was applied to each cycle length scenario costs, utilizing 100% of estimated O&M costs and 11.3% of capital costs. The result of this is in Table 5.

Table 5 – Estimated Annual Line Clearing and Tree-Caused Service Restoration Costs Allocated Through Rates by Customer Type and Cycle Length

Cycle Length (fixed, years)	9	8	7	6	5	4
Residential	$104,845,055	$104,320,403	$105,059,778	$107,082,858	$110,983,234	$117,878,353
Non-Residential	$54,633,819	$54,346,099	$54,716,103	$55,754,080	$57,768,575	$61,340,409

Section 8 – Residential Costs Allocation per Cycle Length

Residential customers make up 88% of electric customers and experience over 90% of electric customer outage minutes. Allocating annual line clearing and tree-caused service restoration costs to residential customers and splitting the optimization analysis to focus on residential customers results in a different optimized cycle length than the preliminary 4-year

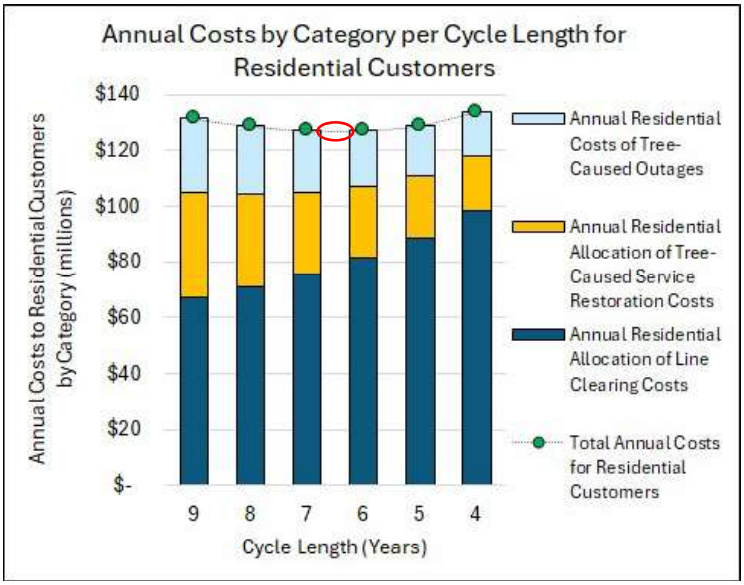
[14] Relationship between the amounts of the revenue requirement (full year convention) and the capital investment, using approved cost of capital, depreciation and property tax rates approved in Case No. U-21389.

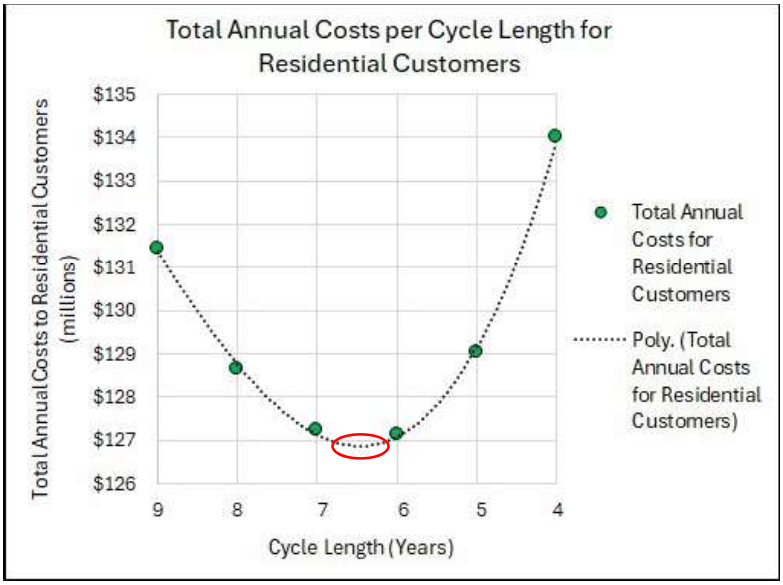
answer for all customer types. The equation illustrating annual costs for residential customers is shown below.

$$\begin{aligned} &Annual\ Costs\ for\ Residential\ Customers \\ &= (Residential\ Allocation\ of\ Annual\ Line\ Clearing\ Costs) \\ &+ (Residential\ Allocation\ of\ Annual\ Tree\ Caused\ Service\ Restoration\ Costs) \\ &+ (Residential\ Costs\ of\ Annual\ Tree\ Caused\ Outages) \end{aligned}$$

Assuming, again, that the cycle length option with the lowest total costs is technically optimal, this results in a cycle length between seven and six years as optimal for residential customers. The optimal point for residential customers is extracted by visualizing the lowest point on a curve fitting annual costs for residential customers by cycle length, as seen in Figure 2. The two graphs in Figure 2 show the same data in two ways: (i) a stacked bar chart to show annual cost breakdown by category per cycle length; and (ii) a dot graph scaled to the range of total annual costs per cycle length for residential customers to make apparent the curve shape and resulting lowest point of the curve, denoting the optimal cycle length. Data displayed in Figure 2 is in Attachment 3, which is attached to this report.

Figure 2 – Annual Costs per Cycle Length for Residential Customers





The lowest point on the curve, denoted by the red oval in Figure 2, represents the cycle length resulting in the lowest annual cost to residential customers.

Section 9 – Conclusion of Formal Optimization Analysis of Line Clearing Cycles

While a combined customer type optimization analysis of line clearing cycles results in a cycle optimization of four years, splitting the optimization analysis to focus on residential customers results in a cycle optimization between seven and six years. It is inequitable to place the financial burden of a shorter cycle length on residential customers to improve the reliability benefit of non-residential customers. Michigan's Healthy Climate Plan defines environmental justice ("EJ") as "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play,

worship, and learn."[15] The concept of EJ indicates the equitable treatment of all people, meaning "no group of people bears a disproportionate share of the negative consequences resulting from governmental, industrial, or commercial operations and policies."[16] The Company prioritizes Michigan communities and application of EJ, driving this formal optimization analysis conclusion towards the prioritization of residential customers. The conclusion of this formal optimization analysis of line clearing cycles is that a cycle length between seven and six years is optimal, which prioritizes residential customers.

Section 10 – Further Considerations for Non-Residential Customers

Outages have a large financial impact on C&I customers. Once the LVD system is on cycle, the Company will evaluate alternate tactics for further C&I outage reduction benefit that are targeted and do not place a significant financial burden on residential customers. To do this, the Company would analyze where C&I customers are located on LVD circuits to understand where alternate tactics could take place to benefit them. Potential alternate tactics for portions of circuits feeding the majority of C&I customers may include but are not limited to: (i) shortened cycle length; (ii) mid-cycle inspection for hazard tree identification and removal; (iii) alternate clearing specifications at the time of maintenance clearing; and/or (iv) non-line clearing alternatives.

[15] Michigan Department of Environment, Great Lakes, and Energy, *Mi Healthy Climate Plan,* page 16 (last visited August 27, 2024), at MI-Healthy-Climate-Plan.pdf (michigan.gov).
[16] Michigan Department of Environment, Great Lakes, and Energy, *Learn About Environmental Justice,* (last visited August 27, 2024), https://www.michigan.gov/egle/public/learn/environmental-justice.

Section 11 – Recommendation

Based on the above, the Company recommends a seven-year effective cycle, consistent with the cycle length recommended in recent rate cases and consistent with the optimal cycle for residential customers, as the optimal cycle length for the Commission's consideration.

Dated: September 3, 2024

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Case No. U-20697
Utility: Consumers Energy Company
Date: September 3, 2024
Attachment 1 of 3

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21585
Exhibit No.: A-47 (PLB-1)
Page: 1 of 1
Witness: PLBolden
Date: May 2024

Consumers Energy Company
Line Clearing O&M Expense
2017-2023 Historical and 2024-2028 Projected

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	**Electric System**	**Expense Type**	**Year**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024** Calendar Year	**2025** Calendar Year	**2026** Calendar Year	**2027** Calendar Year	**2028** Calendar Year	**Test Period** 3/1/25-2/28/26
				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected
2	**Electric HVD**			**$11,393,937**	**$12,035,797**	**$12,211,819**	**$9,169,948**	**$10,739,347**	**$10,987,343**	**$11,301,449**	**$12,279,000**	**$12,294,000**	**$11,972,000**	**$11,645,540**	**$11,300,000**	**$12,240,334**
3		Contractor	Maintenance Clearing	$7,658,022	$8,438,081	$7,571,492	$4,511,969	$4,488,246	$5,157,938	$4,775,712	$5,315,945	$5,313,370	$5,286,488	$5,179,735	$4,811,782	$5,308,890
4		Contractor	Brushing - Cut	$2,388,351	$2,682,986	$3,823,127	$2,365,927	$2,797,068	$3,063,144	$3,601,378	$3,324,000	$3,324,000	$3,000,000	$2,752,100	$2,750,000	$3,270,000
5		Contractor	Brushing - Spray	N/A	N/A	N/A	$1,395,683	$2,407,477	$1,565,658	$1,885,968	$2,490,000	$2,490,000	$2,500,000	$2,500,000	$2,500,000	$2,491,667
6		Contractor	Demand Clearing	$375,620	$152,548	$87,281	$110,249	$98,417	$89,478	$41,202	$65,000	$60,000	$55,000	$60,000	$60,000	$59,167
7		Contractor	Noxious Weed Control	$20,546	$70,093	$52,416	$91,873	$95,891	$152,737	$82,545	$95,000	$95,000	$95,000	$95,000	$95,000	$95,000
8		Contractor	HVD Contract Planning	Note[1]	Note[1]	Note[1]	Note[1]	Note[1]	$175,749	$294,503	$350,529	$358,477	$367,475	$374,524	$382,624	$359,977
9		Labor	HVD Salaries	$709,395	$666,847	$650,467	$672,387	$751,684	$653,623	$516,139	$528,526	$540,153	$552,037	$564,182	$576,594	$542,134
10		Other	HVD Expenses	$242,003	$25,242	$27,036	$21,859	$100,564	$129,016	$104,003	$110,000	$113,000	$116,000	$120,000	$124,000	$113,500
11			**Miles**	**1,019**	**1,081**	**1,102**	**1,116**	**1,178**	**1,106**	**1,153**	**1,166**	**1,168**	**1,171**	**1,173**	**1,173**	**1,169**
12	**Electric LVD**			**$38,359,929**	**$39,912,561**	**$41,078,112**	**$46,104,489**	**$75,827,808**	**$91,016,131**	**$97,792,024**	**$105,371,000**	**$112,792,000**	**$113,122,000**	**$113,428,000**	**$113,752,000**	**$112,847,000**
13		Contractor	Maintenance Clearing	$29,372,207	$31,038,484	$32,173,215	$36,613,687	$62,121,855	$76,623,355	$84,128,930	$87,887,025	$94,966,260	$95,141,216	$95,413,285	$95,664,366	$94,995,419
14		Contractor	Repetitive Outage Zone	$934,465	$2,054,288	$995,575	$1,397,354	$1,711,666	$2,086,904	$1,542,258	$1,500,000	$1,350,000	$1,215,000	$1,090,000	$1,000,000	$1,327,500
15		Contractor	CEMI Clearing	N/A	N/A	N/A	$695,322	$491,257	$506,985	$306,882	$750,000	$750,000	$750,000	$750,000	$750,000	$750,000
16		Contractor	First Zone Clearing	$399,793	$102,600	$1,523,542	$974,275	$405,771	$466,566	$492,077	$1,375,000	$1,525,000	$1,660,000	$1,660,000	$1,660,000	$1,547,500
17		Contractor	LCP Zonal Clearing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$750,000	$750,000	$750,000	$750,000	$750,000	$750,000
18		Contractor	Demand Clearing	$2,642,665	$1,444,228	$1,695,571	$1,281,844	$3,329,375	$2,737,654	$2,058,822	$2,558,000	$2,505,000	$2,505,000	$2,505,000	$2,505,000	$2,505,000
19		Contractor	Brushing - Spray	$1,807,622	$1,679,301	$989,772	$1,538,898	$3,072,427	$3,302,319	$3,396,227	$3,500,000	$3,500,000	$3,500,000	$3,500,000	$3,500,000	$3,500,000
20		Contractor	Distribution Contract Planning	Note[2]	Note[2]	Note[2]	Note[2]	Note[2]	$1,300,689	$2,274,692	$2,320,186	$2,378,190	$2,437,645	$2,498,586	$2,561,051	$2,388,099
21		Labor	Distribution Salaries	$2,388,399	$2,532,425	$2,683,107	$2,509,359	$3,994,189	$3,120,678	$2,877,300	$3,664,790	$4,001,550	$4,097,139	$4,195,129	$4,295,584	$4,017,482
22		Other	Distribution Expenses	$814,778	$1,061,235	$1,017,330	$1,093,749	$701,269	$870,981	$714,837	$1,066,000	$1,066,000	$1,066,000	$1,066,000	$1,066,000	$1,066,000
23			**Miles**	**3,503**	**3,218**	**3,518**	**4,211**	**5,279**	**6,388**	**6,365**	**6,760**	**7,232**	**7,449**	**7,672**	**7,932**	**7,268**
24	**Electric Total**		**O&M Expense**	**$49,753,866**	**$51,948,358**	**$53,289,931**	**$55,274,437**	**$86,567,155**	**$102,003,474**	**$109,093,473**	**$117,650,000**	**$125,086,000**	**$125,094,000**	**$125,073,540**	**$125,052,000**	**$125,087,334**
25		Contractor	Clearing	$45,599,291	$47,662,609	$48,911,991	$50,977,083	$81,019,448	$95,752,737	$102,312,000	$109,609,970	$116,628,630	$116,457,704	$116,255,120	$116,046,148	$116,600,142
26		Contractor	Contract Planning	Note[1], Note[2]	Note[1], Note[2]	Note[1], Note[2]	Note[1], Note[2]	Note[1], Note[2]	$1,476,438	$2,569,195	$2,670,715	$2,736,667	$2,805,120	$2,873,110	$2,943,675	$2,748,076
27		Labor	Salaries	$3,097,794	$3,199,272	$3,333,574	$3,181,745	$4,745,873	$3,774,301	$3,393,439	$4,193,316	$4,541,704	$4,649,175	$4,759,310	$4,872,177	$4,559,616
28		Other	Expenses	$1,056,781	$1,086,477	$1,044,366	$1,115,609	$801,833	$999,997	$818,840	$1,176,000	$1,179,000	$1,182,000	$1,186,000	$1,190,000	$1,179,500
29			**O&M Miles**	**4,522**	**4,299**	**4,620**	**5,326**	**6,457**	**7,494**	**7,518**	**7,926**	**8,400**	**8,620**	**8,845**	**9,105**	**8,437**
30			HVD Cost/Mile	$11,181	$11,134	$11,082	$8,219	$9,117	$9,932	$9,801	$10,531	$10,523	$10,227	$9,928	$9,633	$10,474
31			LVD Cost/Mile	$10,951	$12,403	$11,677	$10,949	$14,364	$14,248	$15,364	$15,587	$15,596	$15,186	$14,785	$14,341	$15,528
32			LVD Target Cycle Miles	8,362	8,362	8,362	8,362	8,362	8,632	8,699	8,714	8,714	8,714	8,714	8,714	8,714
33			LVD O&M Program Miles	3,503	3,218	3,518	4,211	5,279	6,388	6,365	6,760	7,232	7,449	7,672	7,932	7,268
34			Capital Clearing Miles	442	489	301	258	252	221	250	325	325	325	325	326	327
35			Percent of 7 Year Cycle	47%	44%	46%	53%	66%	77%	76%	81%	87%	89%	92%	95%	87%
36			Effective Cycle Years	14.8	15.8	15.3	13.1	10.6	9.1	9.2	8.6	8.1	7.8	7.6	7.4	8.0

Note[1]: HVD Contract Planners were not recorded separately in 2017 - 2021
Note[2]: LVD Contract Planners were not recorded separately in 2017 - 2021

Case No. U-20697
Utility: Consumers Energy Company
Date: September 3, 2024
Attachment 2 of 3

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21585
Exhibit No.: A-48 (PLB-2)
Page: 1 of 1
Witness: PLBolden
Date: May 2024

Consumers Energy Company
Line Clearing Ramp-up Plan Estimated Potential Service Restoration Cost Avoidance

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Year	2019	2020	2021	2022	2023	2019-23	2024	2025	2026	2027	2028
		Actual	Actual	Actual	Actual	Actual	Average	Projected	Projected	Projected	Projected	Projected
2	Line Clearing Program Funding Level ($M)	$53.3	$54.8	$86.6	$102.0	$109.1	$81.2	$117.6	$125.1	$125.1	$125.1	$125.1
3	Actual Tree-Related Primary Outage Incidents with MED	11,247	9,337	12,665	8,256	8,489	9,999					
4	Projected Tree-Related Primary Outage Incidents with MED							9,885	9,690	9,494	9,299	9,103
5	Cumulative Primary Voltage Outage Incidents Reduced with MED from 5-Year Average (Column g, Line 3)							114	309	505	700	895
6	Cumulative Outage Incident Reduction Percent from 5-Year Average							1.14%	3.09%	5.05%	7.00%	8.96%
7	Annual Potential Service Restoration Cost Avoidance ($M)							$0.287	$0.504	$0.515	$0.527	$0.538
8	Cumulative Potential Service Restoration Cost Avoidance from 5-Year Average ($M)							$0.287	$0.791	$1.306	$1.833	$2.371

MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-20697
Utility: Consumers Energy Company
Date: September 3, 2024
Attachment 3 of 3

Consumers Energy Company
Formal Optimization Analysis of Line Clearing Cycles

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Calculation Category**	**Cycle Length (Years)**	**9**	**8**	**7**	**6**	**5**	**4**
2	**LVD Tree-Caused Incidents**							
3		Reduction in Incidents (%)	-0.8%	4.4%	9.6%	14.9%	20.2%	25.6%
4		5-Year Average Incidents	19852	19852	19852	19852	19852	19852
5		Estimated Cycle Incidents	20017	18985	17945	16896	15839	14774
6	**LVD Tree-Caused SAIFI**							
7		Average Customers Interrupted per Incident	54	54	54	54	54	54
8		Estimated Cycle SAIFI	0.573	0.544	0.514	0.484	0.454	0.423
9	**LVD Tree-Caused CAIDI**							
10		Estimated Cycle CAIDI (min)	651.5	628.6	605.5	582.3	558.8	535.2
11	**LVD Tree-Caused SAIDI**							
12		Estimated Customer Minutes (min)	704292097	644529678	586862495	531353209	478064986	427061499
13		Estimated Cycle SAIDI (min)	373.4	341.7	311.2	281.7	253.5	226.4
14	**Customer Costs of LVD Tree-Caused Outages**							
15		Residential Cost of Interruption ($/min)	$ 0.04	$ 0.04	$ 0.04	$ 0.04	$ 0.04	$ 0.04
16		Small C&I Cost of Interruption ($/min)	$ 14.79	$ 14.79	$ 14.79	$ 14.79	$ 14.79	$ 14.79
17		Medium/Large C&I Cost of Interruption ($/min)	$ 235.10	$ 235.10	$ 235.10	$ 235.10	$ 235.10	$ 235.10
18		Residential Outage Minutes (% of total)	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%
19		Small C&I Outage Minutes (% of total)	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
20		Medium and Large C&I Outage Minutes (% of total)	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
21		Residential Cost of Outages	$ 26,590,545	$ 24,334,216	$ 22,156,991	$ 20,061,238	$ 18,049,342	$ 16,123,705
22		Small C&I Cost of Outages	$ 738,588,406	$ 675,915,788	$ 615,440,435	$ 557,228,061	$ 501,344,907	$ 447,857,747
23		Medium/Large C&I Cost of Outages	$ 4,521,508,903	$ 4,137,838,110	$ 3,767,618,590	$ 3,411,252,627	$ 3,069,145,744	$ 2,741,706,710
24	**Costs of LVD Tree-Caused Service Restoration**							
25		O&M Cost per Tree-Caused Outage Incident	$ 2,738	$ 2,577	$ 2,414	$ 2,250	$ 2,085	$ 1,918
26		Capital Cost per Tree-Caused Outage Incident	$ 950	$ 894	$ 838	$ 781	$ 724	$ 666
27		Costs per Tree-Caused Outage Incident	$ 3,688	$ 3,471	$ 3,252	$ 3,031	$ 2,808	$ 2,584
28		Total O&M Costs	$ 54,805,600	$ 48,917,266	$ 43,318,128	$ 38,016,366	$ 33,020,232	$ 28,338,039
29		Total Capital Costs	$ 19,020,549	$ 16,976,974	$ 15,033,766	$ 13,193,764	$ 11,459,831	$ 9,834,854
30		Total Cycle Service Restoration Costs	$ 73,826,148	$ 65,894,241	$ 58,351,894	$ 51,210,130	$ 44,480,063	$ 38,172,892
31	**Costs of LVD Line Clearing**							
32		Contractor Cost per Mile	$ 14,095	$ 13,142	$ 12,132	$ 11,066	$ 9,943	$ 8,764
33		LVD System Miles	61000	61000	61000	61000	61000	61000
34		Annual Cycle Miles	6778	7625	8714	10167	12200	15250
35		Annual Capital Clearing Miles	326	326	326	326	326	326
36		Annual O&M Clearing Miles	6452	7299	8388	9841	11874	14924
37		Total Contractor Clearing Costs	$ 90,937,711	$ 95,921,155	$ 101,765,861	$ 108,893,252	$ 118,061,894	$ 130,788,914
38		Additional Outsource Expenses	$ -	$ -	$ 760,000	$ 1,880,000	$ 3,280,000	$ 5,240,000
39		Demand + Herbicide	$ 6,005,000	$ 6,005,000	$ 6,005,000	$ 6,005,000	$ 6,005,000	$ 6,005,000
40		Distribution Salaries and Distribution Contract Planning	$ 4,524,000	$ 4,785,000	$ 5,046,000	$ 5,307,000	$ 5,742,000	$ 6,264,000
41		Distribution Expenses	$ 1,066,000	$ 1,127,500	$ 1,189,000	$ 1,250,500	$ 1,353,000	$ 1,476,000
42		Total LVD Line Clearing Costs	$ 102,532,711	$ 107,838,655	$ 114,765,861	$ 123,335,752	$ 134,441,894	$ 149,773,914
43	**Allocation through Rates**							
44		Residential - Forestry O&M	66%	66%	66%	66%	66%	66%
45		Residential - Service Restoration O&M	66%	66%	66%	66%	66%	66%
46		Residential - Service Restoration Capital	62%	62%	62%	62%	62%	62%
47		Non-Residential - Forestry O&M	34%	34%	34%	34%	34%	34%
48		Non-Residential - Service Restoration O&M	34%	34%	34%	34%	34%	34%
49		Non-Residential - Service Restoration Capital	39%	39%	39%	39%	39%	39%
50		Service Restoration Capital - Rate Recovery per Outage Incident In a Year	$ 107	$ 101	$ 94	$ 88	$ 81	$ 75
51	**Residential Costs**							
52		Residential Allocation of Tree-Caused Service Restoration Costs	$ 37,378,531	$ 33,362,568	$ 29,543,842	$ 25,927,933	$ 22,520,468	$ 19,327,117
53		Residential Allocation of Line Clearing	$ 67,466,524	$ 70,957,835	$ 75,515,936	$ 81,154,925	$ 88,462,766	$ 98,551,235
54		Total Residential Cycle Costs (Customer Costs of Tree-Caused Outages + Costs of Tree-Caused Service Restoration + Costs of LVD Line Clearing)	$ 131,435,600	$ 128,654,619	$ 127,216,769	$ 127,144,097	$ 129,032,576	$ 134,002,058
55	**Non-Residential (Small C&I and Medium and Large C&I) Costs**							
56		Non-Residential Allocation of Tree-Caused Service Restoration Costs	$ 19,567,632	$ 17,465,279	$ 15,466,178	$ 13,573,253	$ 11,789,447	$ 10,117,731
57		Non-Residential Allocation of Line Clearing	$ 35,066,187	$ 36,880,820	$ 39,249,924	$ 42,180,827	$ 45,979,128	$ 51,222,679
58		Total Non-Residential Cycle Costs (Customer Costs of Tree-Caused Outages + Costs of Tree-Caused Service Restoration + Costs of LVD Line Clearing)	$ 5,314,731,128	$ 4,868,099,996	$ 4,437,775,128	$ 4,024,234,768	$ 3,628,259,227	$ 3,250,904,866

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 3, 2024, she served an electronic copy of **Consumers Energy Company's Line Clearing Program Formal Optimization Analysis of Line Clearing Cycles** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 3rd day of September 2024.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

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UTILITY VEGETATION MANAGEMENT IN NORTH AMERICA:

Results from a 2019 Utility Forestry Census of Tree Activities and Operations



Photo Credit: John Evins-Schroder

College of Natural Resources
University of Wisconsin-Stevens Point

CNUC


Photo Credit: Karen Jenkins

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Suggested Citation: Hauer, R.J. and Miller, R.H. 2021. Utilities & Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities & Operations. Special Publication 21-1. College of Natural Resources. University of Wisconsin Stevens – Point. 69 pp.

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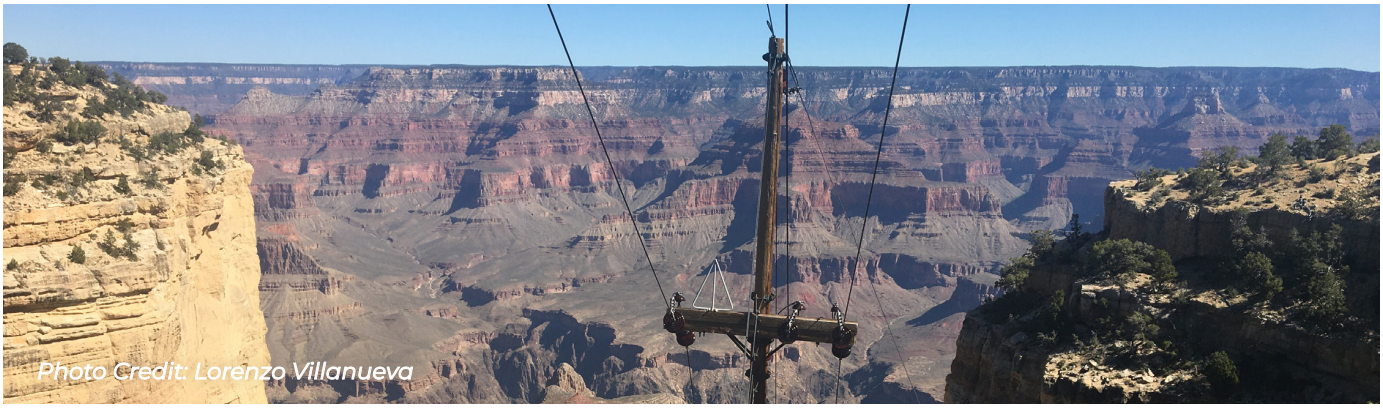
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EXECUTIVE SUMMARY

The Utility Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities & Operations report© describes the current state of utility forestry tree activities and operations. The intent was to enable industry professionals to compare and contrast their program with their peer North American utilities. The ultimate objective of this benchmark study was to further develop an understanding of utility arboriculture, advance the profession, and help utility vegetation managers improve their programs. Further, the study was designed to describe results from the 2019 base year – what utilities are undertaking and accomplishing in the management of vegetation in and near utility corridors. 71 of 210 utilities responded to a request to participate. Participants were determined using a combined list from CNUC and the Arbor Day Foundation Tree Line USA® database. From that list, 16 addresses were not deliverable, duplicates from merged companies with separate addresses or companies returning a non-completed survey. Thus, a total 194 valid utilities could potentially participate for a 36.6% response with participation.

Questions were designed to quantify the following:

- Company Profile
- Program Management
- Integrated Vegetation Management
- Storm Response
- Safety
- Pruning
- Electrical Operations
- Communications

Appendix A details summary statistics from a 34-page questionnaire received between November 10, 2019 and March 9, 2020. Results were tabulated descriptively through mean values, associated variability through the standard error of the mean (SE) statistic, and tests of statistical significance. Respondent perceptions to some questions were ascertained using a five point Likert scale (e.g. 1 = very unimportant, 2 = unimportant, 3 = neither unimportant or important, 4 = important, and 5 = very important).

Key findings from this report include:

Company Profile

- The average customer base of responding utilities was 756,000 with a range of 3,500 to 7.8 million (out of 69 utilities that provided data).
- Most (97.2%) of responding utilities had distribution systems. Fewer (28.2%) were distribution only and nearly 41% were distribution, transmission and generation companies.
- Study participants drew from a cross section of ownerships. Nearly 38.0% are investor-owned, 31.0% are municipal or public utility districts and 20.0% cooperative, comprising nearly 90.0% of respondents. The remaining 10.0% responded state/provincial, federal or other.

Safety

- Nearly all UVM programs (97.0%) sought to learn from safety incidents. Moreover, 97.1% of UVM programs reported close calls.
- Most responding UVM programs did not discipline employees for unintentional safety errors (55.6%). On the other hand, nearly all (95.2%) subjected intentional safety misconduct to progressive discipline.
- Utility Arborist Association (UAA) Safety Summits were rated of neutral importance in a safety program with a mean response of 3.1 out of 5. That was also true for investor owned utilities (IOUs), who responded at 3.2.
- Safety committees were commonly used by two-thirds of utilities, most meeting once a month.
- Several safety subject areas were highlighted as important or very important (4.2 or higher, 1 to 5 scale). Identifying tree risk was ranked highest (4.54). Evaluating safety training and education was lowest (4.17) while still indicating high importance.

Program Management

- UVM programs were overwhelmingly centralized, 79.7% of respondents organized into a single department and another 17.4% centralized by program (i.e., distribution or transmission).
- Nearly all responding UVM programs (92.9%) had a department head. 56% of those department heads hold degrees in natural resources or a related field, 49.2% hold a B.S. and another 6.3% with a M.S. degree. Utility department heads hold the following industry credentials:
    - >> 82.5% ISA Certified Arborists
    - >> 52.4% Certified Utility Specialists
    - >> 20.6% ISA Tree Risk Assessment Qualified (TRAQ)
- Most utilities used multiple contracting strategies for UVM. Time and material contracts were used by 88.6% of respondents, although only 25.7% used it solely. Unit contracts were used by 50.0% of utilities, but only 5.7% solely. Hard price was used by 31.4% of respondents, but only 1.4% used it exclusively.
- UVM programs are most likely housed in the operations (43.9%) or vegetation management (33.3%) department.
- A mean 215.1 (101.8 SE) workers are in a UVM program with a range of 1 to 5,320 people reported.

Pruning

- Respondents reported that an average of 21.3% of trees were in contact with distribution lines at the time of work.
- Overall, 58.5% of responding utilities indicted they perform ground to sky pruning at least some of the time, and 38.5% did so on all locations where trees were off to the side of conductors.
- Mean clearance distances for distribution varied by type of line and aspect. Side and under clearance averaged 10.6 feet (3.2 meters) and 10.9 feet (3.3 meters) for single and three-phase lines respectively. Overhang was on average 3.0 feet (0.94 meters) greater than side clearance and under clearance.
- Pruning objectives are used to guide and prioritize work. Most respondents ranked reliability (4.86), risk reduction (4.73) and clearance distance (4.67) as very important for formulating pruning objectives. While not rated as high, maintaining tree structure (3.86) was ranked as important.
- Pruning Standards and Best Management Practices (BMPs) were ranked important or higher as resources for creating UVM pruning specifications. The ANSI A300 Part 1 Pruning Standard (4.52) and ISA Utility Pruning BMPs (4.44) were rated as very important.

Integrated Vegetation Management (IVM)

- ANSI A300 Part 7 was ranked as important with a 4.12 mean out of 5, followed by the ISA Integrated Vegetation Management Best Management Practices (3.99). The now obsolete UAA Tree Risk Assessment for Fire Prone Areas was lowest ranked with a 2.33 mean.
- Safety and service reliability were ranked equally as the most important reasons to conduct IVM (3.34 mean). Environmental stewardship was ranked as unimportant (2.34 mean).
- Ground surveys were the most common method (4.69 mean) in conducting workload evaluations, followed by aerial photos (2.93), satellite imagery (2.69) LiDAR (2.62) and remote-controlled aerial systems (2.37 mean).
- Based on the previous results, it is not surprising that 85.5% of respondents conduct site evaluations as part of their IVM program.

Electrical Operations

- A mean 23.2% of outages and 21.7% of lost customer minutes were attributable to vegetation.
- Of responding utilities, 64.2% had the same UVM strategy for single and three-phase lines.
- Of various methods employed to decrease vegetation related outages, responding utilities favored greater action thresholds (4.13) and greater clearances at time of work (4.08) on three-phase lines.

Storm Response

- 92.9% of utilities issued a storm response declaration in response to a significant storm event.
- Respondents ranked an emergency operations center (4.31) as the highest storm preparation strategy, followed by pre-storm communication checks (4.17), incident command system (4.16), pre-mobilization (3.86), coordination with local governments (3.73) and storm practice drills (3.66).
- Safety was a very important factor in storm response (4.96). Electric hazard communication protocol (4.57), supervision, (4.56), fatigue (4.55) and wood under tension (4.46) were highly important. Animals and insects (2.74), and equipment rental (2.88) were relatively unimportant.

Communications

- Most UVM programs use multiple ways to communicate with customers. The majority of responding utilities use contract (55.7%) or in-house (57.1%) arborists to contact customers prior to work. 50% use tree crew members as a frontline communication approach. Indirect contacts were less common and included direct mail (14.3%), phone message (14.3%) or door hangers (8.6%).
- Respondents rated brochures (3.57) and social media (3.45) as the most important non-face-to-face communication method. Town hall meetings and email messages or blasts (2.51) were less important.
- Slightly more than half of utilities (54.3%) use customer satisfaction surveys to understand how operations are perceived.



Photo Credit: Joshua Salas

INTRODUCTION

Vegetation management is a major expense for utilities. For many, it is the single greatest operational budgetary line item. Study respondent's average outlay for vegetation management was over $27 million a year, and the cost is justified. Utilities must meet safety and service reliability challenges. The most pressing safety considerations are public electrical contact and fire. For example, in Oregon the most common incidents of people contacting power lines for the period 1996-2015 were tree related. The Oregon Public Commission observes, "If utility customers are going to get injured with high-voltage lines, chances are high that it will be connected to a tree in their yard" (Carter 2016). Fires caused by vegetation contacting power lines can be catastrophic. Recent examples include the autumn 2017 Sonoma, CA firestorm (Avalos 2018) and the 2018 Camp Fire which incinerated Paradise, CA (James and Ortiz 2018).

Trees are a significant source of power interruptions. A 2010 CNUC survey of 68 North American utilities determined that vegetation is responsible for an average of 33% of power outages, resulting in 50% of interrupted customer minutes (Cieslewicz and Porter 2010).

Due to the serious consequences of vegetation conflicts with high voltage lines, utilities are subject to comply with laws and regulations requiring clearance between vegetation and electric facilities. FAC-003-4 is a standard developed by the North American Electric Reliability Corporation (Table 1). It consists of seven requirements intended to prevent cascading outages on the bulk transmission system. Most notably, trees are prohibited form encroaching within a minimum vegetation clearance distance (MVCD), which is a calculated maximum flash distance between transmission lines energized to specific voltages at various elevations. The standard has the force of law insofar as it been adopted by the Federal Energy Regulatory Commission (FERC) and carries possible fines of up to one million dollars per violation per day.

Table 1. Examples of regulations to which utilities are required to comply.

- FAC-003-4: Transmission vegetation management standard. A North American standard developed by the North American Electric Reliability Corporation. The standard has the force of law insofar as it has been adopted by the Federal Energy Regulatory Commission. It has seven requirements intended to prevent cascading outages. Most notably trees are prohibited form encroaching within a minimum vegetation clearance distance (MVCD), which is a calculated maximum flash distance between transmission lines energized to specific voltages and trees. It carries potential penalties of a million dollars per day per violation.
- States and provinces such as California, Oregon and Alberta have clearance requirements between trees and power lines. They are promulgated by the state or provincial regulatory commissions. California also has a state law requiring clearances between trees and power lines in areas of the state that are fire prone.
- International Wildland-Urban Interface Code, which is adopted by many states and local jurisdictions, includes clearances between trees and power lines.
- Some states such as Illinois, require specific cycles on distribution lines.

Study Design and Methods

The project was conducted jointly between the University of Wisconsin – Stevens Point (UWSP) and CNUC. Funding came from CNUC and the UWSP College of Natural Resources. A questionnaire was developed in conjunction with CNUC staff to gather required data. The 2018 "Utility Vegetation Management: The Utility Specialist Certification Study Guide" by Miller and Kempter (2018) was used as an outline for the survey as were past surveys conducted by CNUC (Cieslewicz and Porter 2010, Porter and Cohn 2014, and Porter and Cohn 2016). Prior to delivery of the questionnaire, approval for a human subject study was sought and granted by the Institutional Review Board at UWSP to comply with federal regulations.

The results presented in this report depict the 2019 baseline. They are drawn from a 34-page questionnaire mailed to 210 utilities and received between Nov. 10, 2019

and Mar. 9, 2020 (Appendix A). Six utilities from Canada and 65 from the United States are included (Table 2). The mailing list was developed from two lists, one obtained from CNUC and another from the 2019 Arbor Day Foundation Tree Line USA® program. Duplicate records between the two were combined resulting in a distribution list of 210 potential utilities. This sample is from a population of approximately 3,300 electrical North American utilities. A reported 2,938 utilities in the United States are represented by 168 investor-owned, 812 cooperatives and 1,958 publicly owned utilities (EIA 2019). A reported 380 utilities, 16 major and 364 smaller are located in Canada (Lee and Humphrys 2014). A total 16 utilities were invalid for inclusion due to non-deliverable mail, utilities that merged into one company or companies that did not want to participate. That left 194 possible sample utilities, out of which 36.6% (71) responded to the request.

Questions were designed to quantify Company Profile, Safety, Program Management, Pruning, Integrated Vegetation Management, Electrical Operations, Storm Response, and Communications. Topics for inquiry corresponded to chapters of the aforementioned 2018 utility specialist study guide (Miller and Kempter 2018). Summary descriptive statistics are reported in the 34-page questionnaire as Appendix A. As many as seven contacts were made using the total design method of Dillman et al. (2014).

- A pre-letter mailed on Oct. 14, 2019 explained the purpose of the project and a request to respond by October 23, 2019.
- A postcard reminder was sent Nov. 14, 2019.
- A second survey was sent to non-respondents on Dec. 12, 2019.
- On Jan. 6, 2020 an e-mail reminder was sent.
- A third, short version survey was sent Jan. 22, 2020.
- The final e-mail reminder was sent Feb. 21, 2020 that completed the request to participate.

All statistical analysis used SPSS version 25 (IBM 2017). Within this report we define mean as the arithmetic mean which is the sum of values divided by the total responses. The range is the value from the lowest to highest reported values for a question. The standard error of the mean (SE) was used to denote an estimate of how far the sample mean is likely to be from the population mean. For example, if the current length of the vegetation management cycle is a mean 4.5 (0.18 SE) years, this means the expected population mean is between 4.32 and 4.68. Within the report all error bars in a figure are standard error bars. In many cases we use a five-point Likert scale to ascertain a respondents' ordered opinion of importance (e.g., 1 to 5 scale where 1=very little and 5=very much). The frequency of these responses is reported along with a mean index scale that provides a central tendency of responses. Finally, for some questions we provided the opportunity to expand answers through an open-ended other option, reflecting self-reported information. Overall, the findings in this report provide baseline information for utilities in North America for comparison.

Results

This report documents results from the most recent assessment of Utilities & Vegetation Management (UVM) in North America. Findings in this report document utility baselines from 2019, and are organized by themed sections from the questionnaire. For example, Section I was used to describe attributes of utility companies such as number of customers, business type, ownership structure and line distance under management. Key outcomes from the questionnaire are presented in each section. Not all findings from the questionnaire are reported. Appendix A provides a more complete description of findings.

Table 2. Response rate for the questionnaire by location and overall.

Location	Total Number Mailed	Total Valid Surveys[1]	Number Not Returned	Total Number Returned	% Returned Within Location	% of Total Returns
Canada	15	14	8	6	42.9	3.1
United States	195	180	115	65	36.1	33.5
Totals	210	194	123	71	36.6	36.6

1 *Total number of valid locations after accounting for 16 addresses that were not deliverable, duplicates from merged companies with separate addresses, or companies returning a non-completed survey.*

SECTION I - COMPANY PROFILE

Section I reports on attributes of responding utilities. Questions were created to ascertain customer base, utility structure, and distance of utility line. The total of customers served was asked, which provides a basis to understand the scope of a utility's responsibility to generate or supply electricity through safe and reliable transmission or distribution systems. A utilities business type, which characterizes a utility as having electrical generation, transmission or distribution capability, was ascertained. Ownership structure was used to identify if they are publicly owned, a cooperative, investor-owned utility, or other. Finally, line distance under management, like customers served, was determined as it provides a metric of the size and scope of vegetation management.

Key findings include:

- The total customer base varied among the responding utilities with a mean of 756,600 (162,725 standard error of the mean, SE throughout report) served. The customers of a utility ranged from 3,500 to 7,752,009 (n=69). The results indicate the survey included a broad spectrum of utilities from large-scale organizations to the smallest cooperatives.
- Most utilities (97.2%) provided electric distribution (Figure 1-1). At 69.0%, electrical transmission was common, while less than half (45.1%) were in the generation business.
- Of all respondents, investor-owned comprised 37.8% of the sample (Figure 1-2). Municipal/public utility districts accounted for 31.1% and cooperatives at 20.3% were third most common.

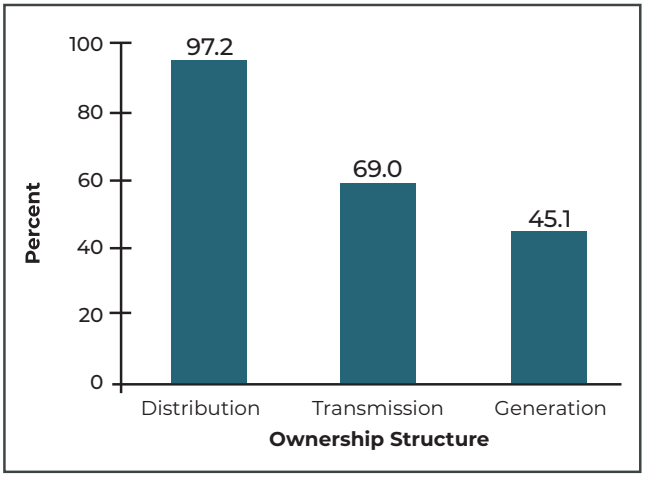


Figure 1-1. Utility ownership structure (n=71).

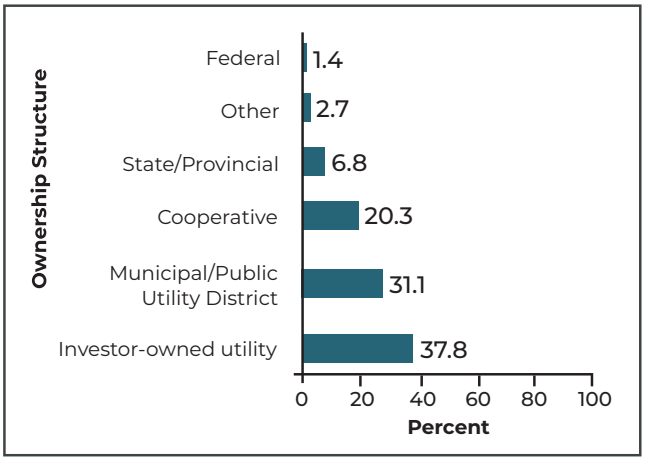


Figure 1-2. The combined business ownership of utilities (n=74).



- State/provincial (6.8%), other (2.7%), and federal (1.4%) collectively represented approximately 10.0% of the sample.
- Most utilities (70.4%) have a business structure with more than one operation, including generation, transmission, and distribution of electricity (Figure 1-3). Many, (40.8%) were in the business of all three. A total 54.9% had a transmission and distribution or distribution only operational model. None of the responding utilities were solely in the electricity generation business.

Distribution lines were most common and 16,523 miles (3,514 SE) was the mean amount under management by a utility (Table 1-1). Single-phase (13,429 mean, 3,415 SE) was more common than three-phase (8,104 mean, 1,961 SE).

- Two-thirds (66.8% mean, 3.0 SE) of primary lines were assessable by aerial lift.

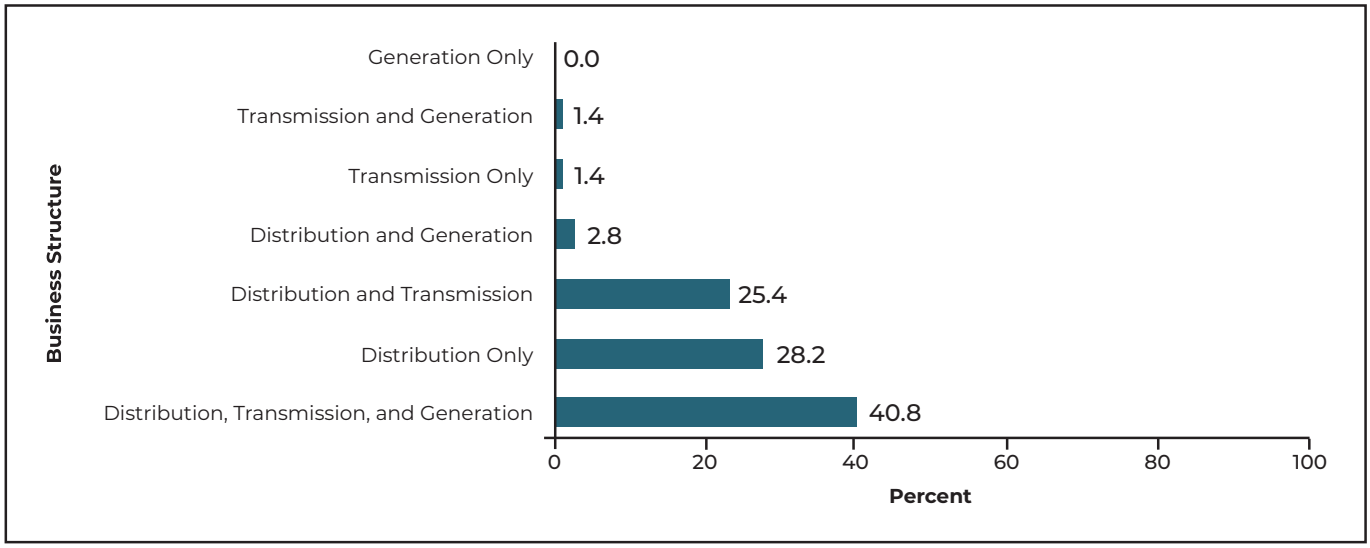


Figure 1-3. The combined business structure of utilities overall (n=71).

Table 1-1. Line distance (mi) of overhead lines type reported by utilities.

Line Type	Mean (mi)	SE[1] (mi)	Range (mi)
Transmission (e.g., 200K line, subject to FAC-003-4)	2,999	963	9 to 31,000
Sub-transmission (e.g., local, not subject to FAC-003-4)	1,936	401	6 to 11,127
Distribution	16,523	3,514	5 to 130,120
Secondary	3,322	1,702	25 to 32,000
Primary[2]	18,778	4,478	5 to 130,120
Three-phase[2]	8,104	1,961	5 to 48,000
Single-phase[2]	13,429	3,415	0 to 83,292

[1] *SE=Standard Error of the Mean throughout report*
[2] *Primary = Three-phase and Single-phase, means do not equal due to non-reporting of data.*

SECTION II - SAFETY

Section II investigated UVM approaches to safety. Safety is rightly a priority in UVM, and a commitment to fewer injuries to people and property damage incidents carry both humanitarian and economic imperatives (Miller and Kempter 2018). Respondents described their approach to incident response with an eye toward improving safety performance. Finally, we determined the occurrence of safety violations and incidents.

Key findings include:

- Learning from safety incidents to improve operations was nearly unanimous, 97.0% communicate lessons learned to others in the organization. Likewise, 97.1% of respondents reported close calls. These results do not mean that every case is reported or communicated, rather, utilities have a system in place to learn and improve safety.
- While not unimportant, the integration of external safety summits and external safety administration appeared to be less common than an internally developed program. For example, respondents on average were neutral (3.1 mean, 1 to 5 scale) to the importance of the Utility Arborist Association (UAA) Safety Summits. Investor owned utilities responded similarly regarding UAA Safety Summits, rating on average 3.2.
- Many approaches are used to communicate safety with utilities, typically in combination (Figure 2-1). A safety meeting was most common (89.1%). Job briefings (56.3%) or department-wide conference calls (28.1%) were also used. Several utilities indicated via self-reporting that communication methods such as email (15.6%) and safety bulletins (6.3%) were common. It is possible these methods would rank higher if they had been directly asked for in the questionnaire.
- 65.0% of respondents report that safety stand-downs are another important way they communicate safety (Figure 2-1). By OSHA definition, “a safety stand-down is a voluntary event for employers to talk directly to employees about safety.”
- Most (70.6%) did not use a third-party safety administrator (e.g., ISNetworld). However, 60% of utilities with more than 10,000 miles of distribution line and 71% of Investor Owned Utilities (IOUs) reported using a third-party safety administrator.
- It was determined employee discipline may result from a safety violation. Fewer than half (44.4%) of utilities reported unintentional safety errors were subject to progressive discipline, however, intentional safety misconduct was likely (95.2%) to result in progressive discipline.

The 95.2% of utilities who reported intentional violations were subject to progressive discipline overwhelmingly agreed that intentional safety violations cannot be tolerated. From that perspective, it is surprising that intentional misconduct is not subject to discipline 100% of the time. On the other hand, the level of respondents who report relying on discipline in response to unintentional safety errors exposes a potential problem in the industry. In their 2010 book “Safe by Accident”, Agnew and

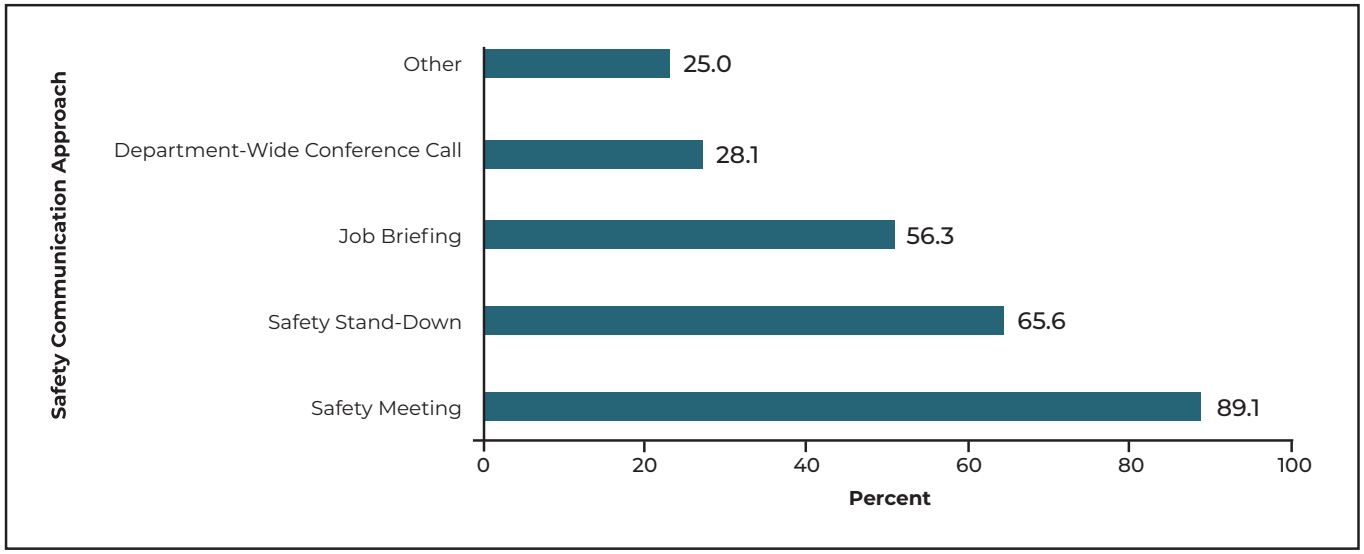


Figure 2-1. The safety communication approaches taken and how lessons learned are communicated to others within an organization (n=64).

Daniels caution that care must be taken in meting out punishment for safety incidents as over-reliance on it can be counterproductive. They observe that safety incidents have multiple causes and it is rare that an individual's behavior is the sole cause of any event. Employees recognize that there is more to any incident than individual fault, and punishment without acknowledging contributing factors, positive reinforcement and a mitigation plan can lower morale, productivity and trust, increase turnover, provoke retaliation and suppress reporting of incidents and close calls. Of these negative, unintended consequences stifling incident and close call reporting is the most serious because it hampers safety culture development.

Learning from safety incidents and close calls is essential in developing a safety culture. Collecting information on incidents and close calls can be applied to a risk matrix as described by McClenahan (2012). The matrix, similar to that used in tree risk assessment, categorizes unsafe acts and conditions on the likelihood they could cause an incident and the potential severity of the consequent event. The information can be used to target training programs to strengthen employee development, establish an early-warning system and objective metrics for employee performance beyond monetary considerations.

- Safety committees were common in two-thirds (67.6%) of utilities. They met a mean 10.6 (1.2 SE) times annually and most (65.9%) met 12 times per year. A company utility representative most commonly (92.9%) chaired the committee. And their purpose was important, having all (100.0%) employees empowered to contribute to the departmental safety policy.

Ideally, safety committee members and management representatives should be drawn from every level in an organization, that means involving front line workers. Front line workers are invariably willing to make tough decisions on how to make the workplace safer. Further, if they are consulted, employees are more willing to accept procedures than if not (Nutter 2012).

- A wide variety of subject areas are considered all important or very important (4.2 or higher, 1 to 5 scale) by safety committees (Figure 2-2). Identifying tree risk was ranked highest (4.54). While still of high importance, evaluating safety training and education was lowest ranked with a 4.17 index score.
- Two-thirds or 67.6% of utilities allow contractors to undertake safety training during billed working hours. A mean 10.1 (2.6 SE) times a year billing is allowed for safety training. Utilities stress safety and a willingness to be partners with contractors indicates they are serious about that commitment.
- External safety authorities (e.g., ANSI Z133, OSHA/ OHS Canada, state/provincial requirements, utility company safety policy and contractor safety policy) were important to the program (4.2 or higher, 1 to 5 scale). The ANSI Z133 American National Standard for Arboricultural Operations – Safety Requirements were the highest ranked (4.54), interestingly higher rated than utility company safety policies, at 4.28 (lowest

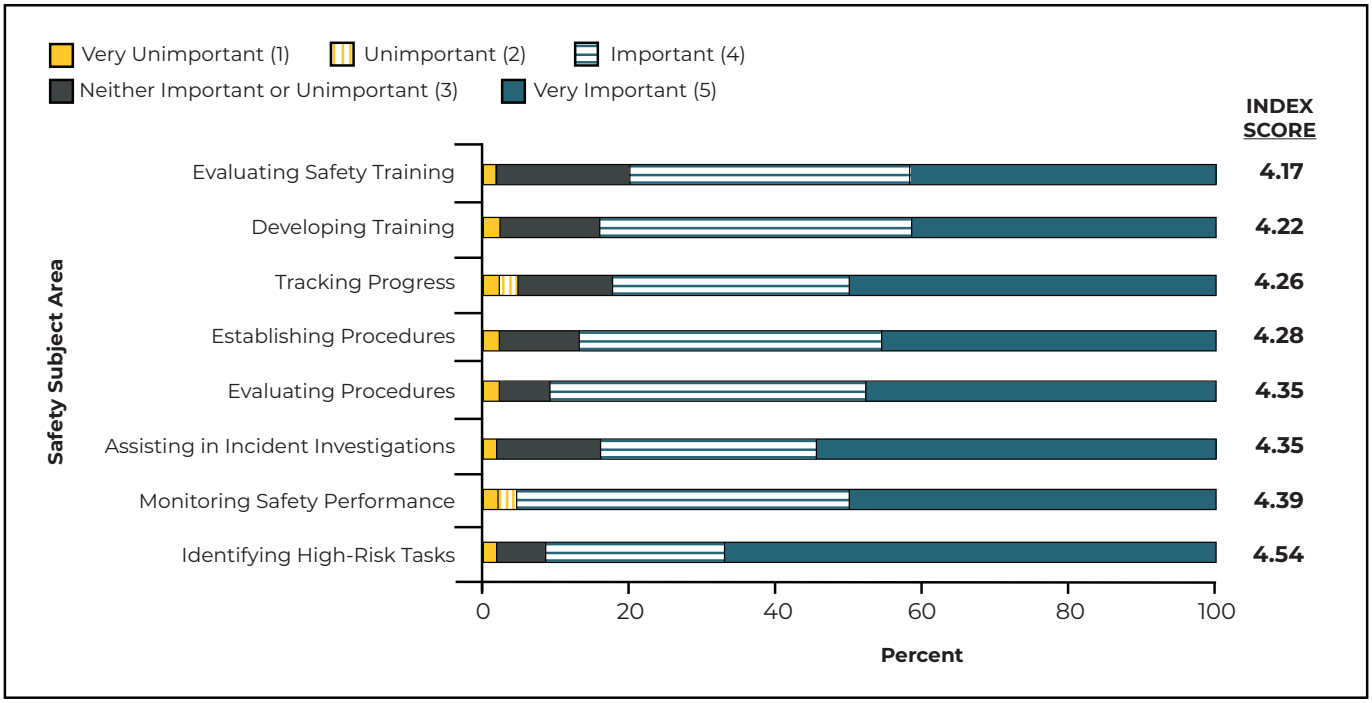


Figure 2-2. The importance of safety subject areas to the safety committee (n=46).



ranked). The results indicate that ANSI Z133 has a strong positive influence on safety in UVM.

- The OSHA Days Away, Restricted or Transferred (DART) metric was calculated by 56.9% of responding utilities. The in-house staff rate (0.23 mean, 0.11 SE) was approximately half the rate reported for vegetation management contractors (0.51 mean, 0.11 SE). This was significantly lower (p=0.023, paired t-test) for the in-house staff (Figure 2-3).
- On average a mean 0.50 (0.19 SE, 0 to 5 range) public utility contacts involving trees occurred annually over the past three years per utility (Figure 2-4). Normalized per 1000-line miles, 0.0328 (0.0186 SE, range 0 to 0.6398) contacts occurred. Reducing the risk of electric contact involving trees is a prominent responsibility of UVM.
- On average a mean 0.76 (0.47 SE, 0 to 25 range) fires involving trees occurred annually over the past three years per utility (Figure 2-4). Normalized per 1000-line miles, 0.0825 (0.0427 SE, range 0 to 2.0284) fires occurred. Fire has been prominent lately, as power line-caused fires in western North America have cost loss of life and billions of dollars of damage.

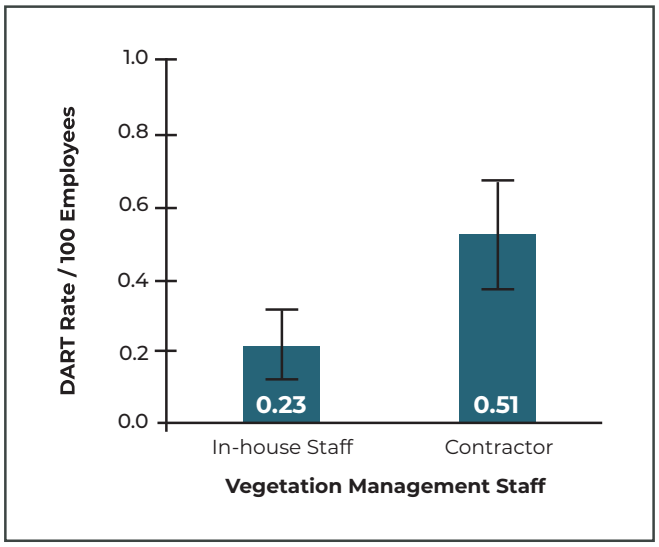


Figure 2-3. Annual DART rate per 100 employees was significantly higher in contracting staff (p=0.023, paired t-test, n=16, error bars are standard error bars).

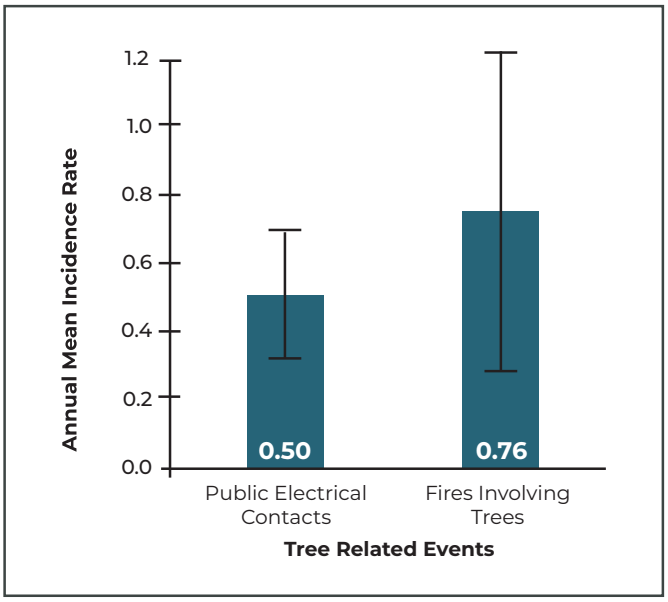


Figure 2-4. Annual tree related events over the past three years with public electrical contacts (n=43) and fires involving trees (n=54) (error bars are standard error bars).

SECTION III - PROGRAM MANAGEMENT

Section III reports on the many UVM tactics utilized by utility companies. Inquiry focused on UVM reporting structures, the title(s) of department heads, the number of people employed and various pay levels, among other variables. Metrics used to track production, where work occurs and devices used to collect information were also reviewed.

Moreover, this section reports on the importance of credentials, industry affiliations and how well management understands UVM. This report discusses budgets, inspection of work, allocation of time and money by utility line type, time-based work cycles and if work is done differently based on utility line type.

Key findings include:

- None of the responding utilities indicated their UVM program was decentralized. Most were centralized as a single department (79.7%), others centralized by program (17.4%). Two utilities (2.9%) self-reported other structures with one specifying under contract and the other saying centralized at the state office level.

In contrast, 89.0% of programs responding to CNUC's 2002 industry survey and 77.0% of respondents to the 2006 survey were centralized in a single department. In 2002, 7% of respondents reported they were centralized by program and in 2006 that number rose to 13% (Cieslewicz and Porter 2010). Four percent of responding programs in both 2002 and 2006 were decentralized. It is clear that over the past 18 years UVM programs have been overwhelmingly centralized, with most organized in a dedicated department and a few centralized by program (e.g., distribution and transmission).

- Most UVM programs had a department head (92.9%). Utilities reported the department head title was most commonly manager (28.1%), director (14.1%) or supervisor (14.1%) of vegetation management. The "other" option was selected by 28.1% of respondents who reported some variation of manager (10.9%), supervisor (4.7%) or superintendent (4.7%). This is consistent with results from 2002 and 2006 when 91% and 90% of responding programs had "system forester or equivalent" respectively (Cieslewicz and Porter 2010).
- A variety of credentials were held by UVM department heads (Figure 3-1). Many (56.0%) hold a B.S. (49.2%) or M.S. (6.3%) in a natural resources or related field (e.g., agronomy, arboriculture, forestry, horticulture, urban forestry, wildlife biology). Other self-reported forms of education (e.g., A.A.S. forestry, engineer, environmental science, MBA) were provided by 21.9% of respondents. Credentials such as the International Society of Arboriculture (ISA) Certified Arborist (82.5%), ISA Certified Arborist Utility Specialist (52.4%), or ISA Tree Risk Assessment Qualification (20.6%) were commonly held.

In 2002, 71.0% of utilities responding to a CNUC industry survey indicated the "person in charge" had a green industry educational background in natural resources, but that fell to 46.0% in 2006. Further, 50.0% of programs were led by a certified arborist in 2006, and 33.0% by ISA Utility Specialists. 80.0% of 2002 and 90.0% of 2006 respondents considered ISA Certified Arborist credentials to be important. 45.0% of 2002 and 57.0% of 2006 respondents considered ISA Utility Specialist certifications to be important (Cieslewicz and Porter 2010).

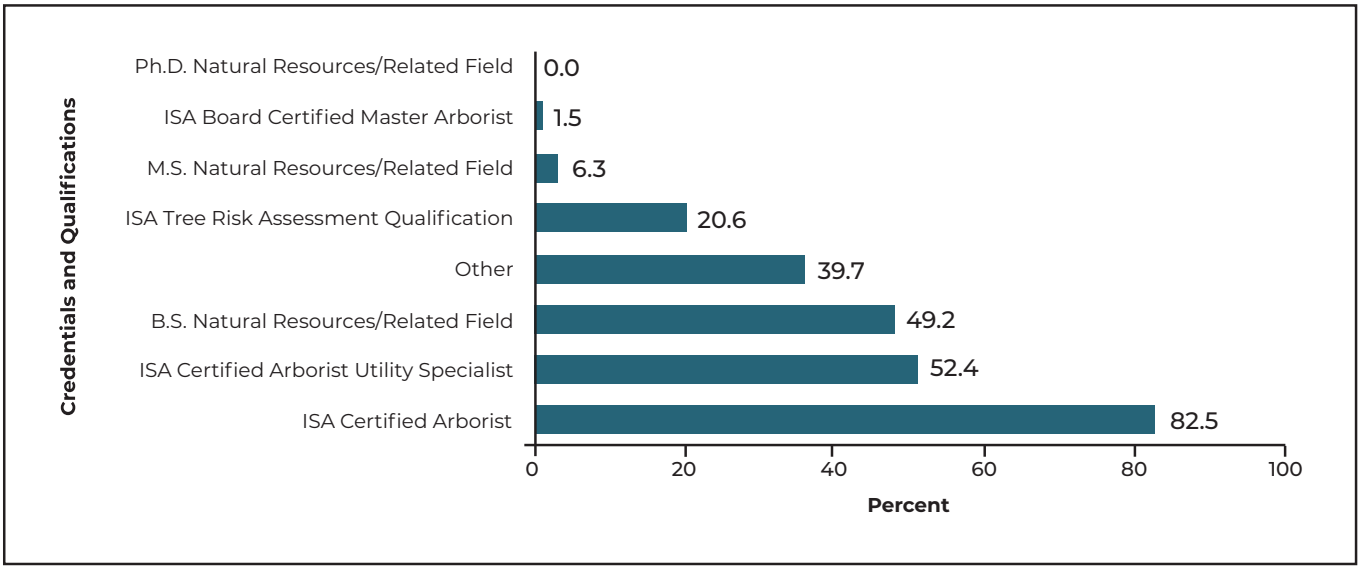


Figure 3-1. Education levels and other credentials held by the UVM department head (n=64).

The results suggest that ISA credentials are increasingly valued in utility vegetation management.

- UVM programs were most likely housed in the operations (43.9%) or vegetation management (33.3%) department (Figure 3-2).
- A mean 215.1 (101.8 SE) workers are in a UVM program with a range of 1 to 5,320 people reported.
- A mean 39.5% (5.5 SE) of total FTE's are directly responsible for managing the UVM program with a range of 0 to 100 reported.
- A mean 4.8 (0.3 SE) levels of management are involved in directing the UVM program. This includes both utility employees and contractors (Figure 3-3).
- UVM work for responding utilities is pre-planned or inspected ahead of tree crews 89.9% of the time. Both contract workers (52.3%) and company employees (39.1%) who were not tree crew members performed this task (Figure 3-4). Tree crew members uncommonly (5.3%) performed pre-planning or inspection.

The results suggest the overwhelming majority of UVM programs consider pre-planning and inspection, whether by in-house or contractor employees, to be important. Pre-planning is widely used for a number of reasons.

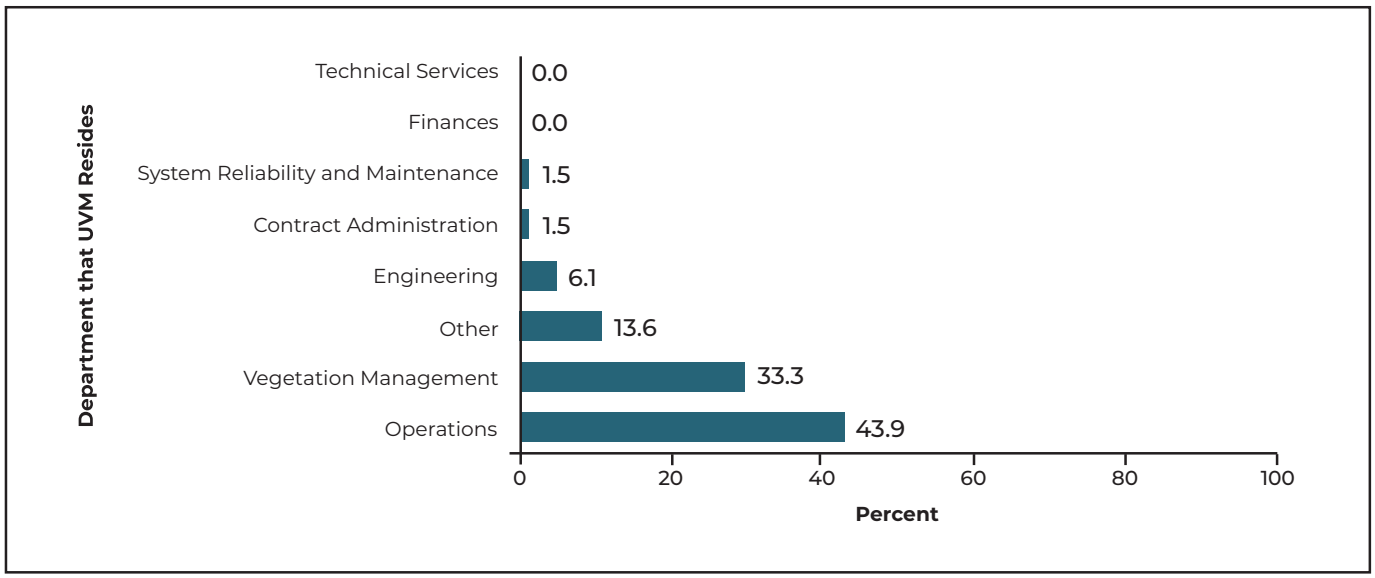


Figure 3-2. The department that the UVM department resides (n=66).

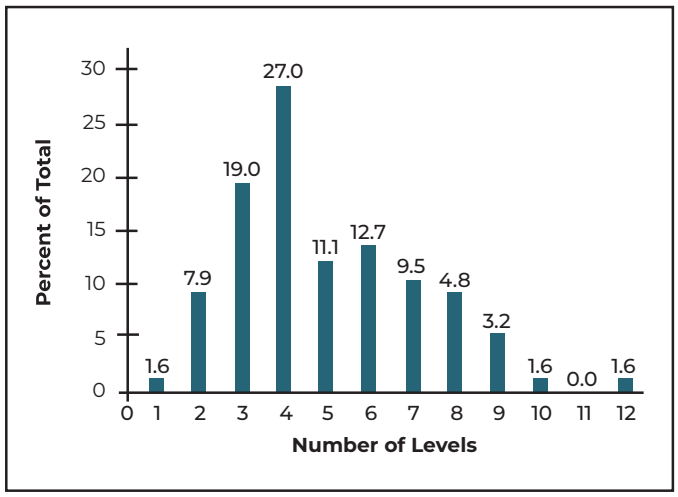


Figure 3-3. The levels of management that are involved in directing the UVM program (n=63).

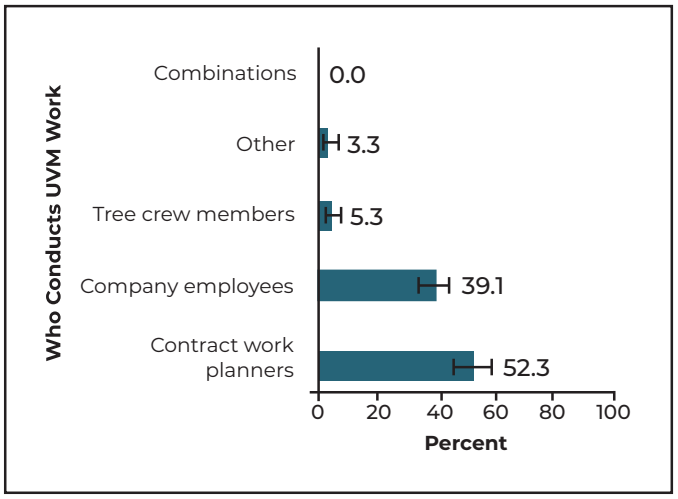


Figure 3-4. The workers who conduct UVM work pre-planning or inspection, ahead of tree crews (n=61).

First, a single individual identifying work and planning the quickest route is more efficient than a tree crew with multiple members doing so. Second, many property owners and other stakeholders expect and deserve time to discuss what is planned on their property. If that discussion waits until a tree crew arrives, workers may be idle while the conversation is underway. Finally, vegetation management often interfaces with more customers than any other utility department. That interaction represents the company for better or worse. Communicating is outside of the skill set of many tree crew members and it is unrealistic to expect successful communication as a secondary assignment performed in addition to tree work.

- Most participating UVM programs reported leveraging technology as vegetation management data is collected through a variety of electronic technologies including tablet or iPad (58.5%), laptop (46.2%), mobile phones (38.5%) or desktop computers (36.9%). Surprisingly, paper is also commonly used (55.4%) to collect vegetation management data (Figure 3-5).
- GIS-based software is regularly used (72.1%) to spatially relate vegetation data. A variety of attributes (e.g., address, circuit, pole number, tree/brush unit) are used to identify work locations (Figure 3-6).
- Nearly all utilities (91.1%) reported they track the amount of accomplished work.
- Table 3-1 summarizes production measurements collected to track UVM. The number of trees removed was the most common production measurement with over 70% of utilities reporting this for distribution (75.4%) and transmission lines (70.5%). Line distance (75.4%) and trees pruned (60.7%) were also common metrics collected for distribution lines. Areas treated with herbicide (68.2%) or saplings/brush removed (59.1%), along with trees pruned (56.8%), were common transmission line metrics collected.
- UVM programs maintain a variety of industry affiliations. The International Society of Arboriculture (83.1%), Utility Arborist Association (81.5%), and Arbor Day Foundation Tree Line USA (80.0%) were very common affiliations. All other cited affiliations were 15% or below (Appendix A, Section 3 Question 19).
- ISA credentials were important to responding utilities. The ISA Certified Arborist (4.27, 1 to 5 scale), ISA Certified Utility Specialist (3.99), and Tree Risk Assessment Qualification (3.51) were important. Board Certified Master Arborist (2.70) and Certified Municipal Specialist (2.48) credentials were relatively unimportant to responding utilities (Figure 3-7).
- Respondents provided their total annual UVM budget (Figure 3-9). A mean $27,182,769 (7,021,420 SE) was spent in 2018. The amount spent ranged from $50K to $320M. Approximately half (53.7%) indicated their budget was stable over the past five years. Nearly half (52.9%) indicated their budget was not adequate. Of these utilities, the budget was a mean 28.9% (4.3 SE) below the identified need.

In 2014, 31.0% of 29 responding utilities responded

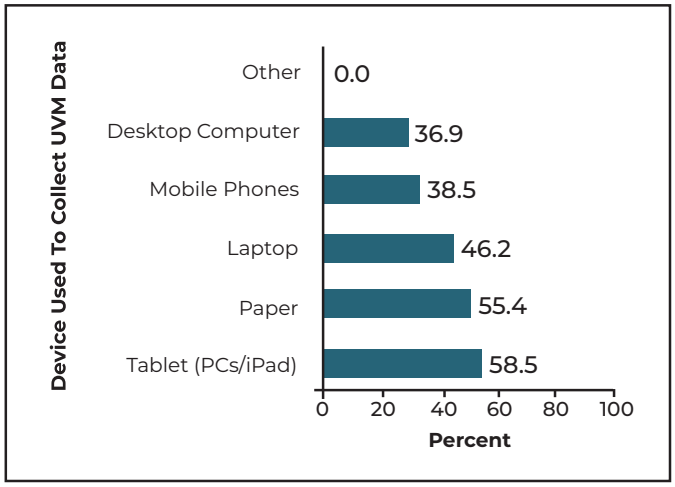


Figure 3-5. Devices used to collect vegetation management data (n=65).

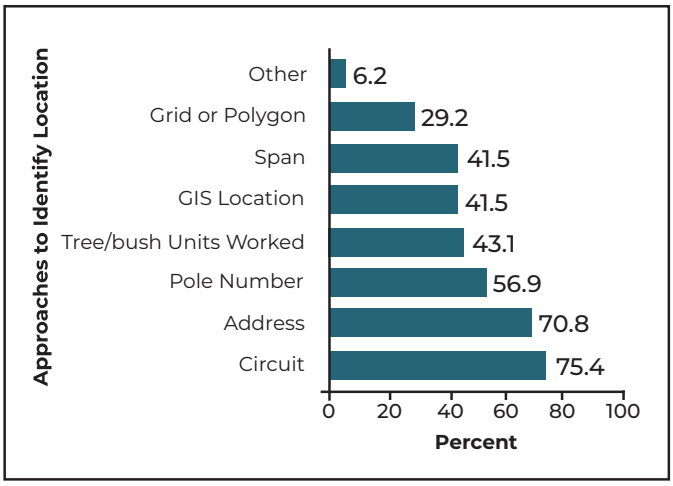


Figure 3-6. Work locations used to identify vegetation management data (n=65).

their budget was met at least 95.0% of the time, 14.0% responded their budget was significantly lower, and 10.0% that their budget is usually nowhere close to meeting the UVM program needs (Porter and Cohn 2014).

- In 2016, 52.0% of utilities indicated their budget met at least 98.0% of their UVM schedules. 24.0% indicated their UVM budget was significantly lower than needed, 6.0% that their budget was nowhere close to UVM needs, and another 6.0% indicated their budget is usually less than UVM needs.
- Most utilities use line item (49.3%) or program (23.9%) based budgeting. None used performance. Entrepreneurial (17.9%) and zero-based (9.0%) were also used. See Appendix A Section 3 Question 27 for definitions.
- An array of contracting types were used for UVM, with a mean of 2.0 (0.1 SE). Time and material were most reported, with 88.6% using this structure and 25.0% solely using this system. Unit based contracting was used by 50.0% but only 5.7% used it exclusively. Hard price contracts were used by

Table 3-1. Measurements collected to track utility vegetation management.

Production Measurements Collected	N-size	%
Distribution Line	**61**	**-**
Area (ft^2 / m^2) of saplings (brush) pruned	11	18.0
Area (ft^2 / m^2) of saplings (brush) removed	24	39.3
Area (ft^2 / m^2) of saplings (brush) treated with herbicide	23	37.7
Distance (km or mi) of line cleared	46	75.4
Trees in contact with the line at the time of maintenance	5	8.2
Trees per mile / km worked	19	31.1
Trees pruned	37	60.7
Trees removed	46	75.4
Other	6	9.8
Transmission Line	**44**	**-**
Area (Acres or ft^2 / hectare or m^2) of saplings (brush) pruned	12	27.3
Area (Acres or ft^2 / hectare or m^2) of saplings (brush) removed	26	59.1
Area (Acres or ft^2 / hectare or m^2) of saplings (brush) treated with herbicide	30	68.2
Trees pruned	25	56.8
Trees removed	31	70.5
Other	11	25.0

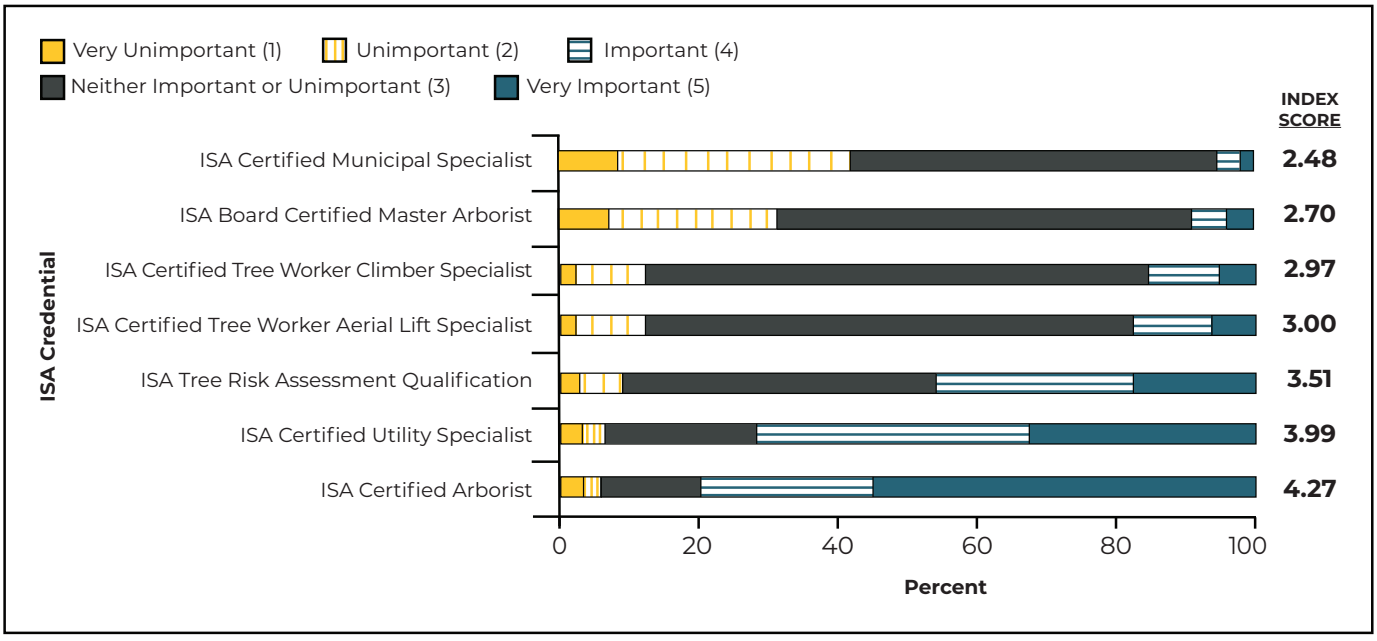


Figure 3-7. Importance of the following credentials to the UVM program (n=64 to 70).

31.4% but only 1.4% use it as their only contracting strategy. While we collected percentages on types of contracting used, we did not collect the budget percentage allocated to contracting types. The results suggest that many UVM programs use a variety of contracting strategies on their system, depending on what works best under particular circumstances.

- Respondents were asked how well management understands UVM, rating from very little (1 scale) to very much (5 scale). Overall, most factors were rated above neither little nor much (3 scale) or above much (4 scale) (Figure 3-8). Variability of natural systems was rated lowest with a 3.33 index score. The highest rated were the effect of UVM on reliability (4.57), compliance (4.45), benefits of tree removal (4.36), need for professionalism in UVM (4.27), and liability (4.26).

Anecdotally, many utility arborists have expressed frustration in the level of understanding their management has about UVM. These responses suggest this is a misperception and utility management actually have good command of the UVM issues, or at least those investigated in this study.

- Post-work inspection was very common with 94.4% of respondents indicating their program does such. A mean 81.3% (4.3 SE) of work is audited. Results indicate the overwhelming number of responding utilities recognize the importance of quality control. Many utilities post-inspect 100.0% of their work.
- Quality assurance (QA) and quality control (QC) methods were commonly used (Figure 3-10). 100.0% field auditing was most common (69.0%) for transmission lines but only used by 39.0% of respondents for secondary distribution lines. A 100.0% drive-by assessment was second most common. Sampling was used approximately 20.0% of the time. Finally, it was uncommon for respondents to have no QA or QC program, and only absent on distribution lines (i.e., all respondents had some QA or QC on subtransmission and transmission lines).
- Conducting UVM work on a time-based cycle was most common (88.7%). A reactive, just in time, or reliability-based system was uncommon, each used by 3.1% of utilities. A total 9.2% of respondents used a variable work cycle. A regular work cycle was most common as 81.5% of responding utilities used this approach. On average a 3.8 (0.2 SE) year cycle was desired, while utilities were currently on a 4.5 (0.2 SE) year cycle to complete all work. Thus, utilities on average were 0.7 (0.2 SE) years or 19.3% behind their desired cycle.
- The average rate of pay increased from ground worker ($17.10) to planner QA specialist ($32.94) (Table 3-2). In most cases pay level was higher for contractors, with the one exception of planner QA specialist position. Rate of pay does not include fringe rates, thus total compensation was not ascertained. The average department head (in-house employee) salary was $116,288 (Table 3-2). An in-house utility arborist/manager

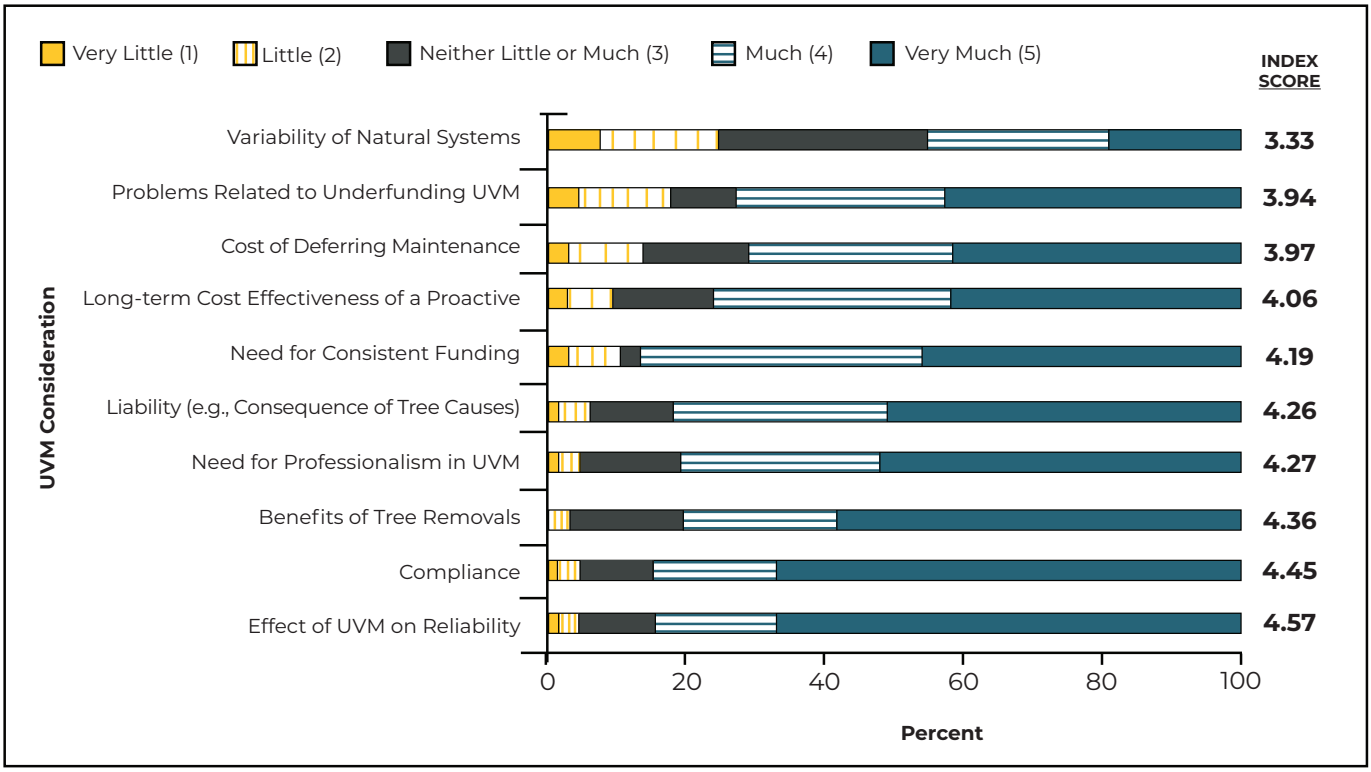


Figure 3-8. Importance of the following considerations to the UVM program (n=64 to 70).

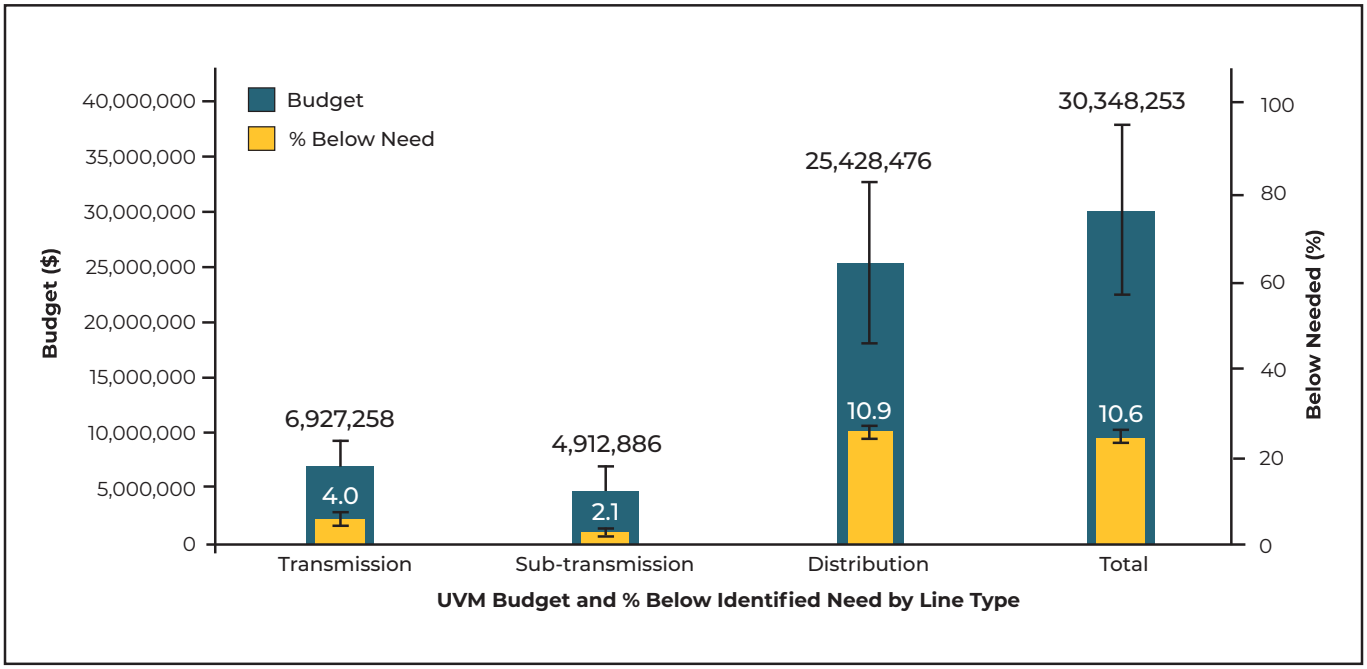


Figure 3-9. The UVM program budget (left axis) for all responding utilities and the below identified need (right axis) for the 53.0% of utilities who indicated their budget was inadequate for their identified needs (n=4 to 59).

one level below the department head on average made $86,877. An in-house utility arborist/manager two levels below the department head on average made $71,813. Management positions in-house paid a higher salary than contracted positions.

Browing and Wiant (1997) found the cost of working trees beyond the time they reach conductors increased by 20.0% a year before inflation. Recent work by CNUC (Chen and Vanderhoof 2020) indicated that at a project level, there is no correlation between time since last worked and cost. They concluded that while the cost of working trees increased in correlation with time, other factors such as weather, growth rates and pruning methodology seemed to affect project level cost. Condition-based scheduling using pre-established work thresholds is considered best practice rather than strict time intervals (Miller 2014) and Chen and Vanderhoof's results affirm that best management practice. Evidence suggests that UVM might de-emphasize cycle work in favor of evidence-based scheduling.

- The vast majority (78.8%) of respondents used a grid (polygon) basis for UVM work. Whether a line was three-phase or single-phase had little effect on cycle length with most (90.6%) using the same cycle length for both line types.

The proportion of responding utilities that schedule by grid has markedly increased in recent years. 32.0% scheduled by grid in 2002 and 11% of responding utilities scheduled by grid in 2006 (Cieslewicz and Porter 2010). The advantage of scheduling on a circuit basis is that it systematically completes all the line on a circuit as part of a project. It is the best way to maximize reliability and allows for a direct correlation to be made between vegetation management and electric system reliability.

The disadvantage is the amount of line in a circuit can vary as load is shifted, particularly in urban or other areas of high demand. Shifted line segments can be stranded and missed between cycles resulting in unacceptable safety and service reliability risks. Further, potential variable line distances mean that data from one time a circuit is worked cannot always be compared to that of another time worked. While working on polygons or grids enables consistent data collection from one treatment to another, line on a particular circuit is often divided between grid boundaries, meaning reliability correlation can be compromised (Miller and Kempter 2018). Responding utilities have evidently found the consistency of working grids or polygons is preferable to the reliability correlation attendant to circuit scheduling.

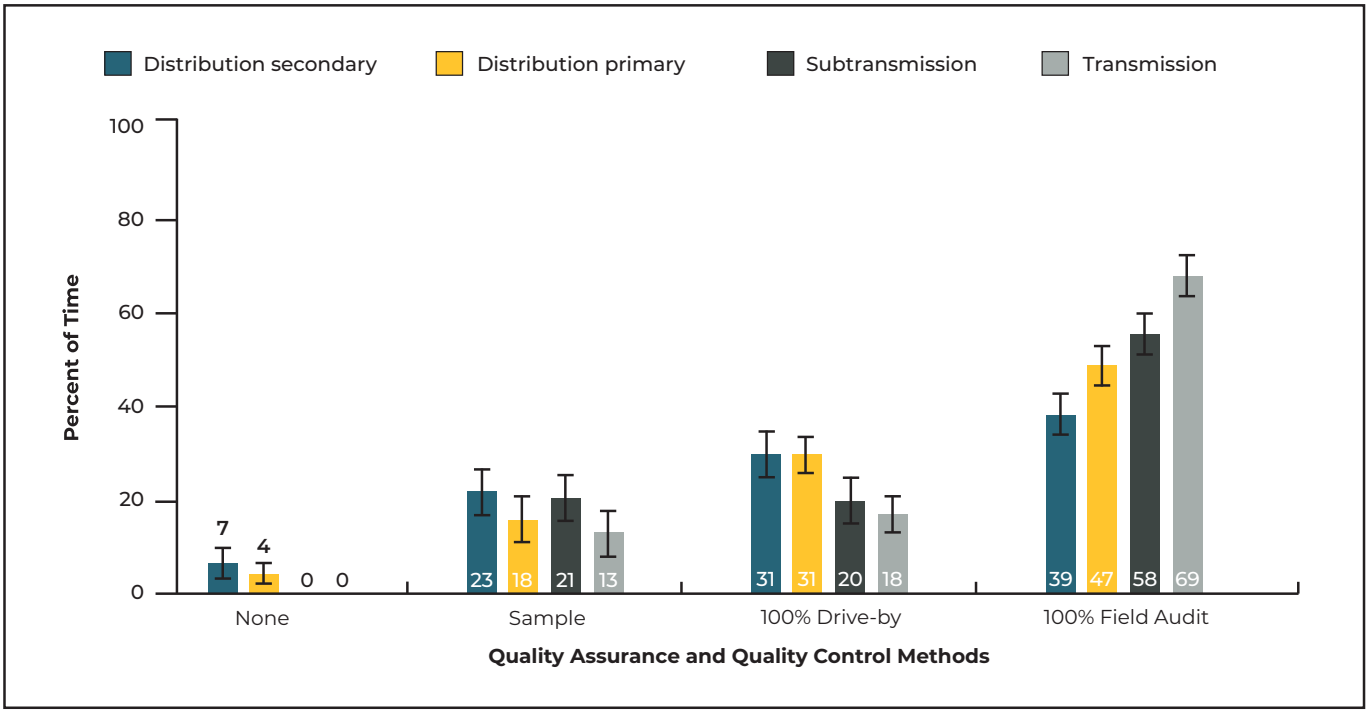


Figure 3-10. The percent of time that is allocated for the following quality assurance and quality control methods (n=32 to 58).

Table 3-2. Average salary or hourly pay rate by UVM position.

Position Categories	In-House			Contractor		
	Pay Level $[c]	SE	N-size	Pay Level $[c]	SE	N-size
Management Annual Salary						
Department Head	116,288	5,461	37	82,500	7,500	2
Utility Arborist/Manager[a]	86,877	3,353	36	64,556	6,702	5
Utility Arborist/General Foremen[b]	71,813	3,857	25	63,775	5,223	14
Field Utility Arborist/Forester Hourly Pay						
Ground Worker	17.10	2.10	6	19.94	1.58	29
Chemical Applicator	19.57	3.81	5	26.69	2.73	15
Qualified Utility Arborist Trainee	19.61	4.01	4	21.58	1.10	23
Qualified Utility Arborist	26.47	2.12	10	24.85	1.46	28
Crew Leader	29.27	2.41	11	30.14	1.86	32
Planner QA Specialist	32.94	3.35	7	27.53	2.78	19
Other	31.25	---	1	33.28	11.73	2

a *1 level below department head*
b *2 levels below department head*
c *Pay does not include fringe benefits*

SECTION IV - PRUNING

When done correctly, tree pruning is effective in reducing conflict between trees and utility lines where removal is not possible or appropriate. The science and application of tree pruning has advanced in the past few decades. Knowledge on how to properly prune trees, the limited use of wound coverings, where to prune, tree biomechanics and standards have progressed markedly.


Photo Credit: Bill Spencer

Questions in this section established the state of trees at time of pruning. Examples of inquiry include whether a utility uses a ground to sky approach and where this work is done. The various considerations (e.g., line location, reliability, risk reduction, pruning cycle length) for tree pruning and their importance were given. The target pruning distance from tree to distribution line type (clearance) was established. The importance of pruning factors, pruning objectives and standards was determined. Finally, how utility line location affects decision making was ascertained (Figure 4-1) along with pruning factors, objectives, and considerations (Figures 4-2, 4-3, 4-4).

Key findings include:

- The tree canopy positions relative to lines at time of pruning was determined. A mean 21.3 % (3.5 SE) of trees were in contact with the line at time of pruning. A mean 24.6 % (3.7 SE) of trees were over-hanging the line.

A high percentage of trees in contact with the line at time of work raises costs (Browning and Wiant 1997) and is an indicator of inadequate financial resources (Miller and Kempter 2018). Recall that nearly half (52.9%) of respondents indicated their budget was not adequate. Of these utilities, the budget was 28.9% (4.3 SE) below the identified need. Being behind in cycles and a high percentage of trees growing in the lines at the time of work contribute to a spiral of decline that could result in unacceptable safety and service reliability risks.

- Chemical pruning programs were uncommon, only 13.4% of responding utilities state it is part of their operation. Chemical

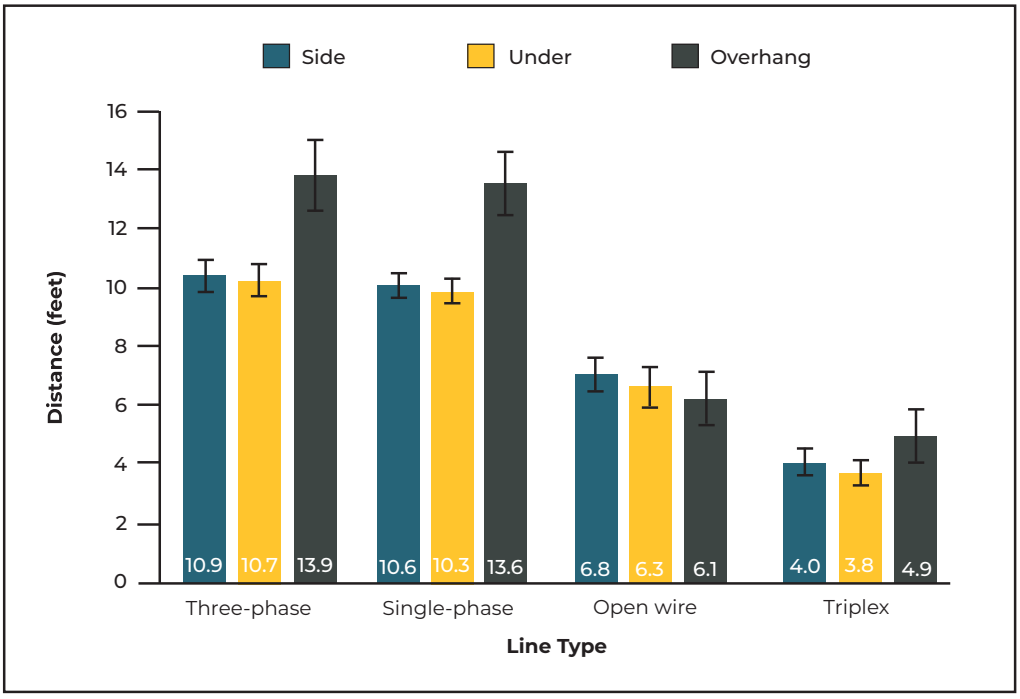


Figure 4-1. Pruning clearances by electric distribution line type (n=17 to 46).

pruning involves spraying branches with fosamin amomonium herbicide. Fosamin ammonium has limited translocation within plants and it inhibits bud development in many species (Senseman 2007). When properly applied it kills target stems without harming the rest of the plant. While it has efficacy in some cases, it is evidently not in widespread use in UVM.

- A mean 58.5% of responding utilities indicated they perform some aspect of ground to sky pruning. Over one-third (38.5%) practiced ground to sky pruning in all locations. Nearly half (48.7%) did so around three-phase lines and one-quarter (25.6%) applied this approach to rural locations. If you apply all locations (e.g., 58.5% said all locations), then 82.1% of three-phase lines and 59.0% of rural locations used ground to sky pruning.

Ground to sky pruning clears all stems of the subject trees growing toward conductors, including those above the lines, in an effort to eliminate branches that might expose power lines to mechanical breakage or cross phasing resulting in outages. The authors are unaware of any research conducted to determine the efficacy of the practice. On one hand it's a matter of common sense. On the other, ground to sky pruning may circumvent mass damping properties in trees. Mass damping is a tree adaptation to withstand dynamic loading due to winds. It involves a complex structure including the trunk, side branches and sub-branches of all sizes, including twigs. When subject to wind, each stem absorbs the dynamic force asynchronously, often preventing the tree system from devolving into damaging large sway motions that could result in tree failure (James 2003). Removing all the side and sub-branches from the tree system effectively lion tails trees, which could result in whole tree or major limb failure. The results in this questionnaire show mass damping was the lowest rated factor in obtaining clearances (Figure 4-2), suggesting that compromising this tree characteristic is either not a problem or utility specialists are unaware the technique may be counterproductive. Given that the majority of utilities prune ground to sky, research is needed to determine the efficacy of the practice.

- The pruning distance from electrical distribution lines was dependent upon the line type (Figure 4-1). Triplex lines were commonly not maintained (11.0%) or pruned to relieve strain and abrasion (52.0%). A mean 4.0 ft. (0.5 SE) or 1.2 m (0.2 SE) of side clearance and 4.9 ft. (1.1 SE) or 1.5 m (0.3 SE) of overhang clearance was reported. In contrast, approximately 95% of distribution lines (single and three-phase) were pruned to a set distance rather than no maintenance (2-3%) and cleared only to relieve abrasion (~3%). The mean side distance of 10.6 ft. (0.5 SE) or 3.2 m (0.2 SE) for single-phase and 10.9 ft. (0.6 SE) or 3.3 m (0.2 SE) were reported for single-phase and three-phase lines, respectively. The overhang distance was reported to be approximately 3 ft. (0.9 m) greater than the side distance for single- and three-phase lines. Side and under line distance were similar in all cases. Several utilities did not specify an exact distance, rather they self-reported that distance was dependent upon tree species (e.g., growth rate, conifer versus deciduous), and line location (e.g., urban versus rural, all overhang is cleared ground to sky, all under branches removed).

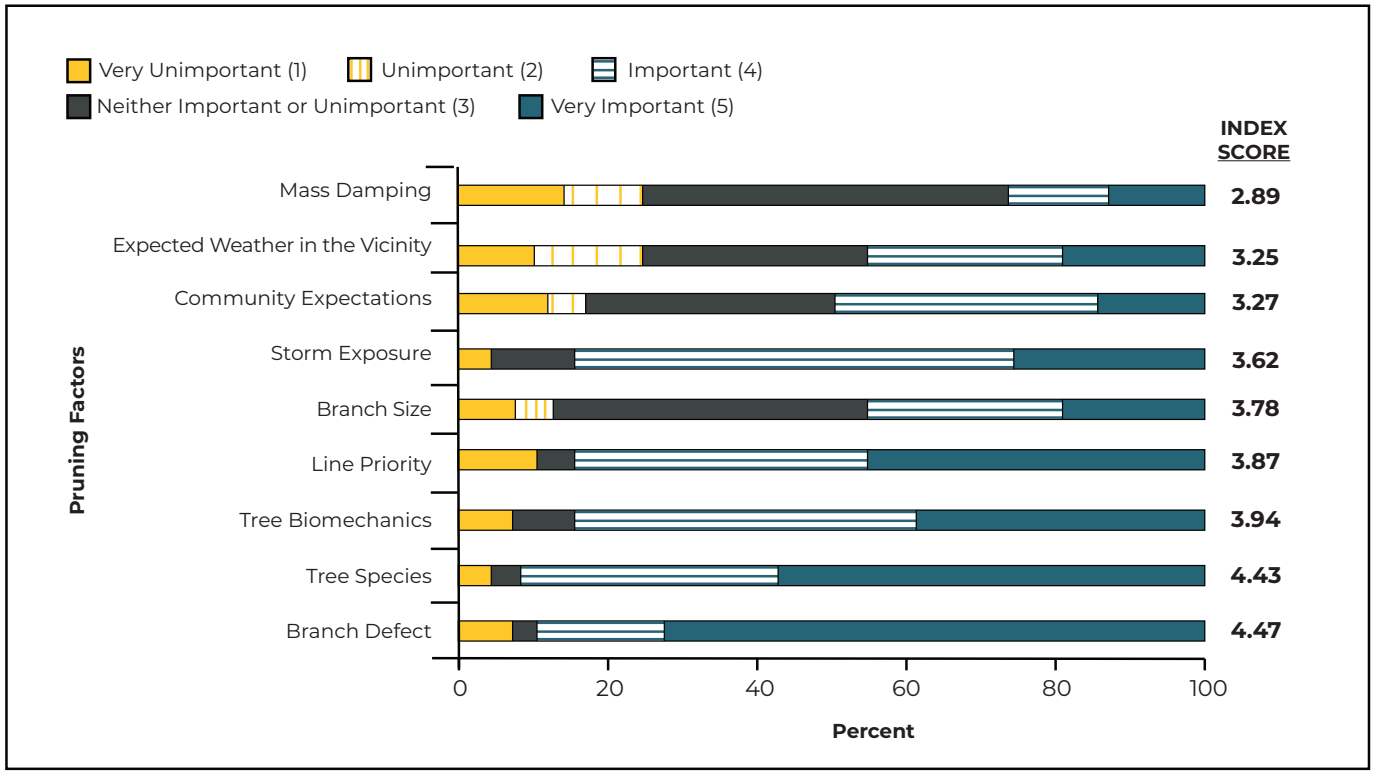


Figure 4-2. Pruning factors used to determine overhang clearance distances of trees from electrical distribution lines (n=54 and 64).

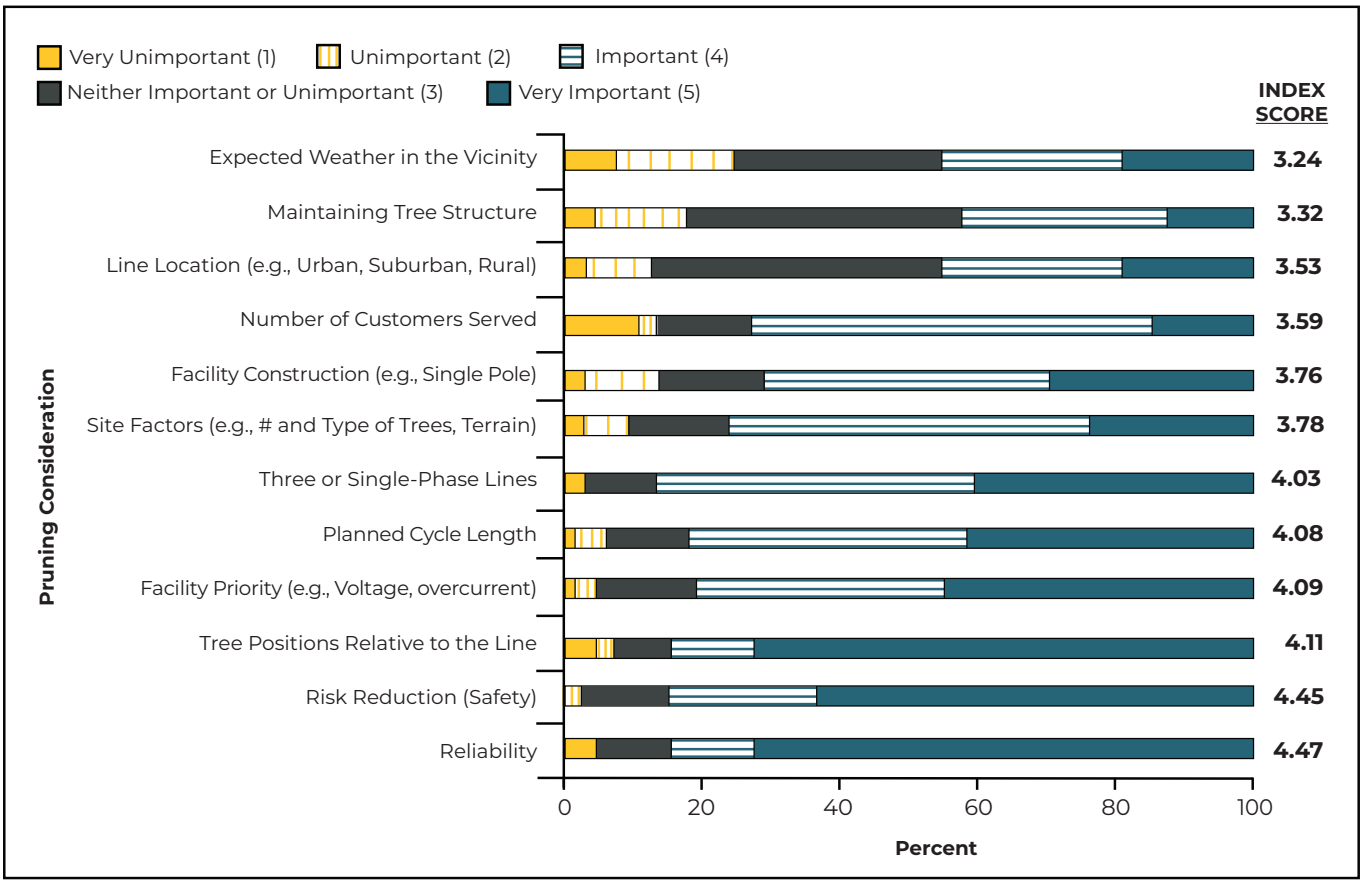


Figure 4-3. Pruning considerations used to determine clearance distances of trees from electrical utility lines (n=63 to 64).

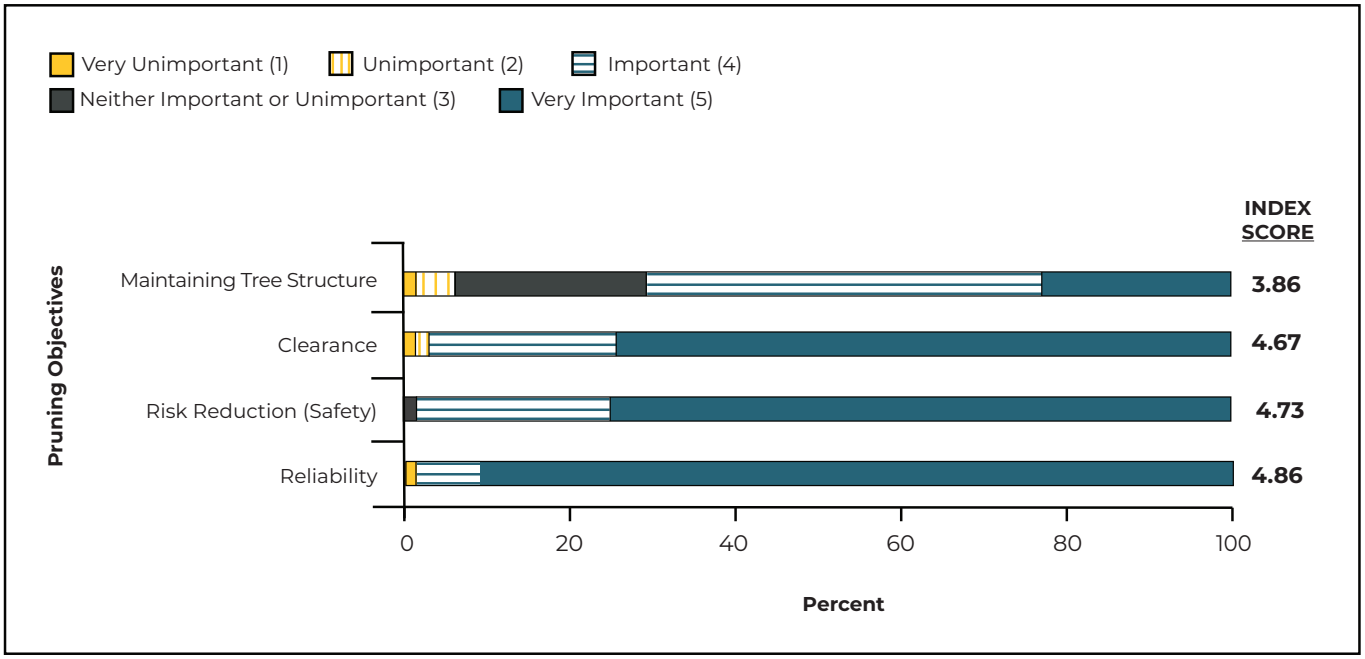


Figure 4-4. The importance of pruning objectives to a UVM program (n=64 to 66).

It is not surprising that triplex lines are either not pruned or minimally cleared to relieve abrasion or tension. Triplex are insulated distribution secondary lines that carry 110/220V in North America. Since they often serve only a single or a few customers at most outages carry less urgency or consequences. Secondly, due to their low voltage and insulation, vegetation caused outages are usually mechanical. With that in mind, the strictest clearance requirements for triplex lines in the United States can be found in the California Public resource code section 4293 and Oregon Administrative Rule 860-024-0016, which require clearing only to relieve deflection or abrasion of lines energized below 750 and 600 volts respectively. The mean of 4.0 ft. (1.2 m) of side and 4.9 ft. (1.5 m) of overhang distance for triplex indicate responding utilities that clear triplex go far beyond what is minimally expected.

The 2004 ISA Best Management Practices for Utility Pruning of Trees (Kempter 2004) advises that pre-established clearances between electric facilities and tree stems take into consideration the following variables:

- tree species characteristics
- anticipated growth rate
- natural tree structure
- expected reaction to pruning
- wood strength
- tree health
- anticipated time until next scheduled pruning
- type of facility (construction type, voltage and other factors)
- presence of other trees
- buildings
- terrain

It also advises pruning cuts should be made at the next suitable natural target proximal to the specified clearance distance rather than at a strict clearance distance.

- Many pruning factors are used to prioritize distribution overhang clearance (Figure 4-2). Branch defect (4.47) and tree species (4.43) were the most important (Figure 4-3). Mass damping of trees was ranked the lowest (2.89), near the important or unimportant ranking. Tree biomechanics (3.94), line priority (3.87), branch size (3.78) and storm exposure (3.62) were collectively ranked as important for guiding overhang pruning clearance.
- The importance of pruning considerations in the context of clearance distance varied (Figure 4-3). Using a 1 to 5 scale (5 highest), reliability (4.47) and risk reduction (4.45) for safety were the highest rated considerations. Tree position relative to the line (4.11), facility priority (4.09), planned cycle length (4.08), and three- or single-phase lines (4.03) were rated as important. Expected weather in the vicinity (3.24) and maintaining tree structure (3.32) were the lowest ranked, however, still above a neutral 3 index score.

Mass damping was discussed in relation to ground to sky clearance earlier. The low importance of the concept as a consideration in overhang clearance might suggest a need for research on the topic.

- Pruning objectives are used to guide and prioritize work (Figure 4-4). Most respondents ranked reliability (4.86), risk reduction (4.73) and clearance distance (4.67) as very important for formulating pruning objectives. While not rated as high, maintaining tree structure (3.86) was ranked as important. Respondents ranked Pruning Standards and Best Management Practices as important or higher as resources in creating UVM pruning

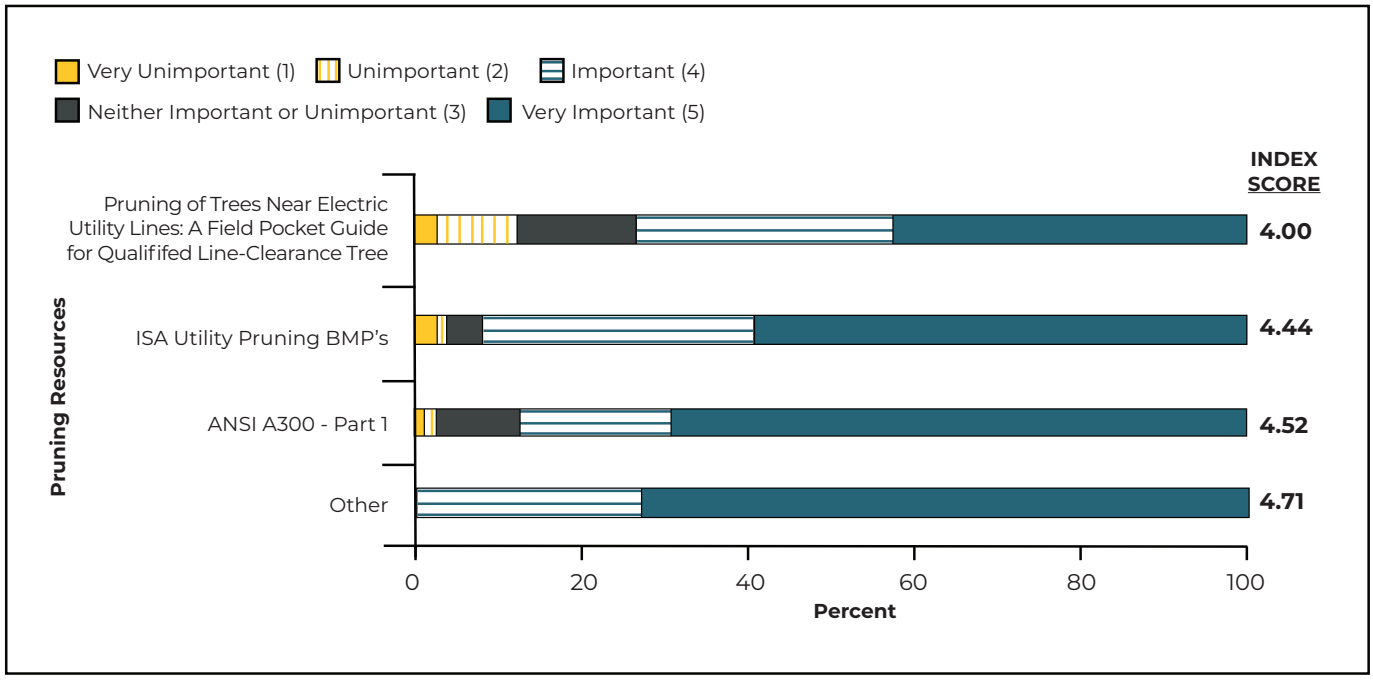


Figure 4-5. The importance of pruning standards, best practices, and resources to a UVM program (n=71).

specifications (Figure 4-5). Specifically, the ANSI A300 Part 1 Pruning Standard (4.52) and ISA Utility Pruning BMPs (4.44) were rated as very important.

- Several other (4.71) considerations were self-reported for creating specifications including ANSI A 300 Part 7 IVM, UAA BMPs closed chain of custody, BMP of fire prone states and provinces, OSHA, FAC003-4 and company or program specifications.
- The location of electrical lines is important or very important to developing a pruning program (Figure 4-6). A rural (3.77) location was ranked lowest in importance to developing a program and the ranking increased in more populated urban (4.03), suburban (4.06), and urban-rural interface locations.

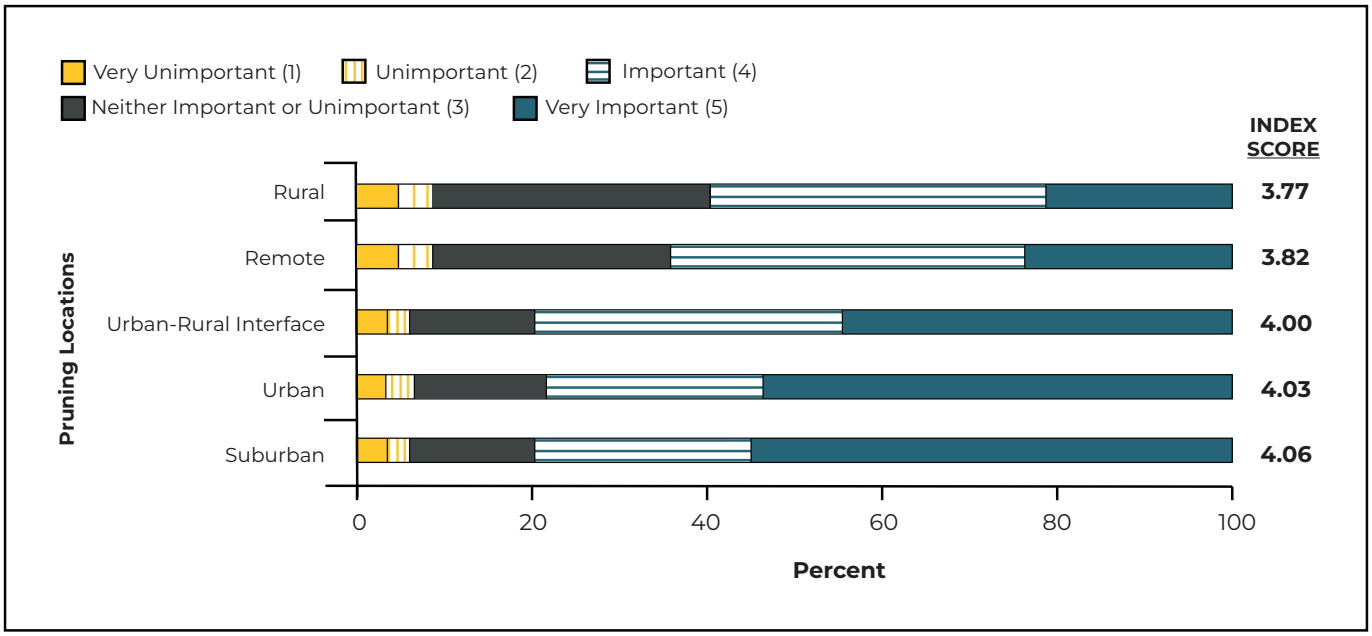


Figure 4-6. The importance of pruning of locations with developing a pruning program (n=64 to 66).



SECTION V - INTEGRATED VEGETATION MANAGEMENT

Section V describes different aspects within Integrated Vegetation Management (IVM). Respondents were asked to report the information they collect for their IVM program including data that depicts operations and methods for conducting workload evaluations. The importance of objectives used to drive IVM was identified. Likewise, how well industry standards are incorporated into operations and action thresholds for decision making were reported. The use of tree growth regulators and mechanical pruning approaches were quantified. Finally, the use and importance of IVM methods (e.g., biological, chemical, cultural, engineering, physical) was reported.

Key findings include:

- The most common information collected for IVM programs included address (71.4%), species (60.3%) and pole number (50.8%) (Figure 5-1). Growth rate (15.9%), tree orientation (17.5%) and tree risk assessment rating (19.0%) were least common.
- Utilities ranked five reasons for conducting an IVM program on a 1 (very unimportant) to 5 (very important) scale. Safety (3.34 mean, 0.17 SE) and service reliability (3.34 mean, 0.20 SE) were highest ranked. Compliance (3.04 mean, 0.18 SE) and cost-effectiveness (2.95 mean, 0.16 SE) were similar and intermediate. Environmental stewardship (2.34 mean, 0.21 SE) was ranked lowest for importance.

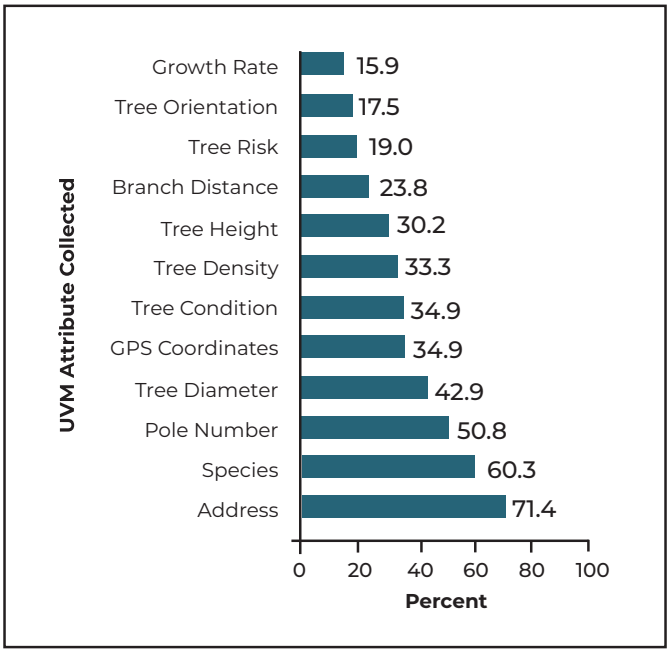


Figure 5-1. Information collected by utilities for the IVM program (n=63).

The low value given to environmental stewardship indicates more work needs to be done to raise awareness

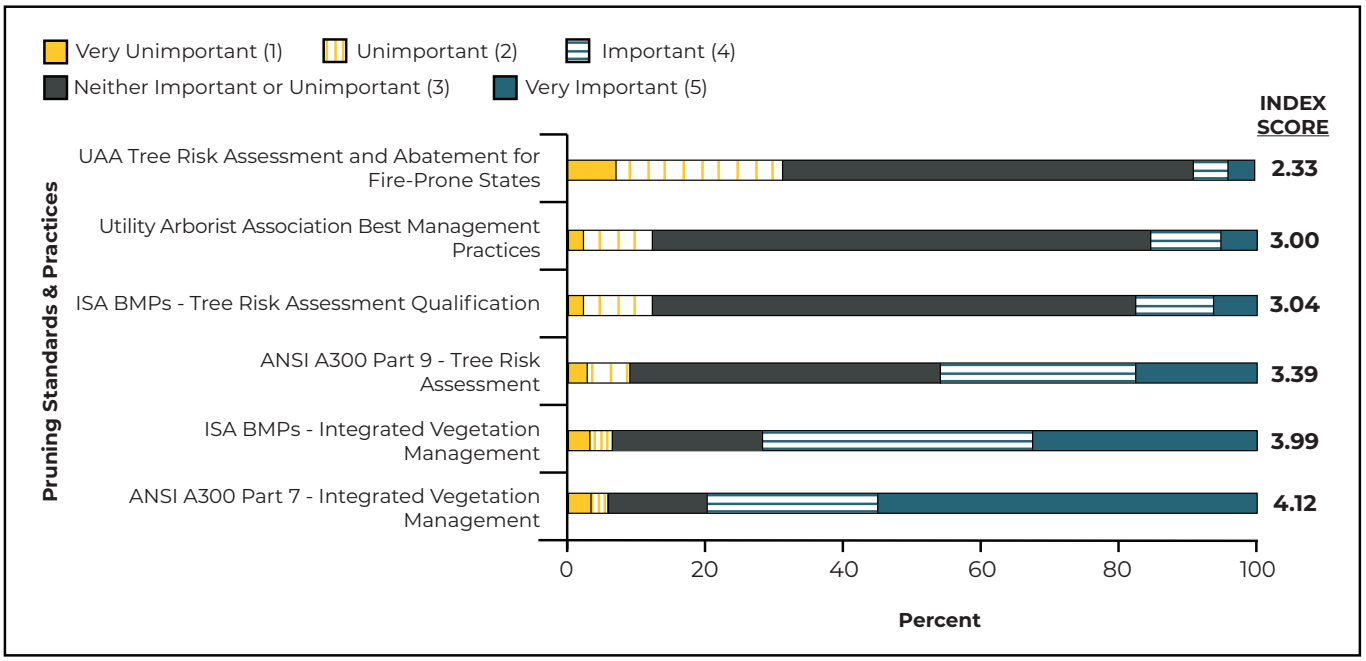


Figure 5-2. The importance of incorporation of standards and best management practices into IVM programs (n=68 to 69).

of its importance. Environmental Stewardship is a core value of the UAA, whose website observes, "The UAA recognizes that excellence in the UVM industry can only be achieved when we treat our rights-of-way as ecosystems and take the best possible care of the natural resources we have been entrusted to manage".

- Standards are incorporated into IVM programs in a variety of ways (Figure 5-2). Not surprising, the ANSI A300 Part 7 – Integrated Vegetation Management standard was ranked highest at a 4.12 mean index score (1=very little and 5=very much) followed by the companion ISA BMP – Integrated Vegetation Management (3.99), the ANSI A300 Part 9 Tree Risk Assessment (3.39) and companion ISA BMP – Tree Risk Assessment Qualification (3.04). The UAA tree risk assessment for fire prone areas was lowest ranked (2.33 mean index score), however, it was higher ranked for utilities in fire prone areas.

Since the questionnaire was distributed, the UAA and ISA published a utility tree risk assessment best management practice (Goodfellow 2020). This publication is not limited to fire prone areas and given its more wide application will likely receive broader acceptance in UVM.

- The development and use of IVM objectives are commonly done to manage utility lines (Figure 5-3). Not surprising, service reliability (4.84) and safety (4.73) were the highest ranked. Facility protection (4.49), cost efficiency (4.45), and compliance (4.25) were also ranked important. Even the lowest ranked objective, cultural site protection (3.57) was leaning toward an important consideration.
- Respondents provided the methods they used to conduct workload evaluations. Ground evaluations were rated by far the most important (4.69). The following methods, while not unimportant, were rated lower: aerial photos (2.93), satellite imagery (2.69), LiDAR (2.62) and unmanned aerial systems (2.37).
- The use of the ISA Tree Risk Assessment BMP was uncommon, 79.4% said it was not part of their IVM program as a tree risk assessment system. This does not mean utilities are not conducting tree risk assessment, rather the ISA system is not commonly used.

It is surprising that the Tree Risk Assessment BMP was used by such a small number of utilities' IVM programs. Tree risk assessment should be an important part of any

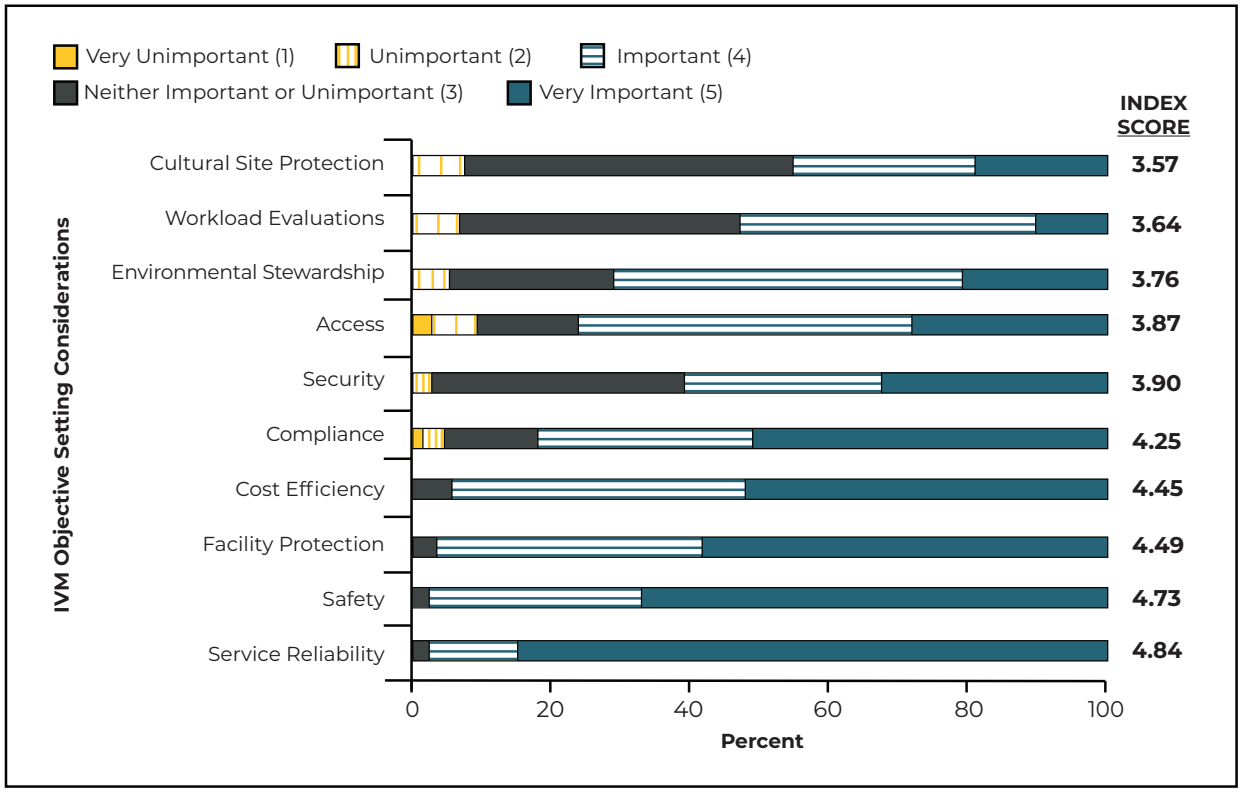


Figure 5-3. The importance of IVM considerations with setting IVM objectives. (n=60 to 64).

IVM program. Perhaps it is because the IVM BMP did not have a specific tree risk assessment dedicated exclusively to UVM for the period covered by the survey.

Since this survey was conducted, that shortcoming has been remedied with the release of the 2020 ISA and UAA Utility Tree Risk Assessment BMP (Goodfellow 2020).

- Based on the previous results it is not surprising that 85.5% of respondents conduct site evaluations as part of their IVM program.
- Figure 5-4 details the variety of site evaluation attributes. Safety was most common, and 85.7% of respondents said it was part of site evaluations. Right-of-way width (78.6%), access routes (76.8%), line voltage and criticality (76.8%), and line location (73.2%) were also common. In contrast, soil types (23.2%), fire risk (25.0%), and archaeological and cultural issues (30.4%) were the least common site evaluations.
- 76.8% use action thresholds in decision making. Minimum clearances were most common, applied by 86.8% of responding utilities (Figure 5-5). This was followed by length of time (69.8%), tree risk rating (52.8%), vegetation height (49.1%), and vegetation density (37.7%). Minimum vegetation clearance distance (MVCD) FAC-003-4 was the most common (67.2%) criteria used to develop tolerance levels. Compliance with state/provincial or federal regulations was used by 44.3% to set tolerance levels.

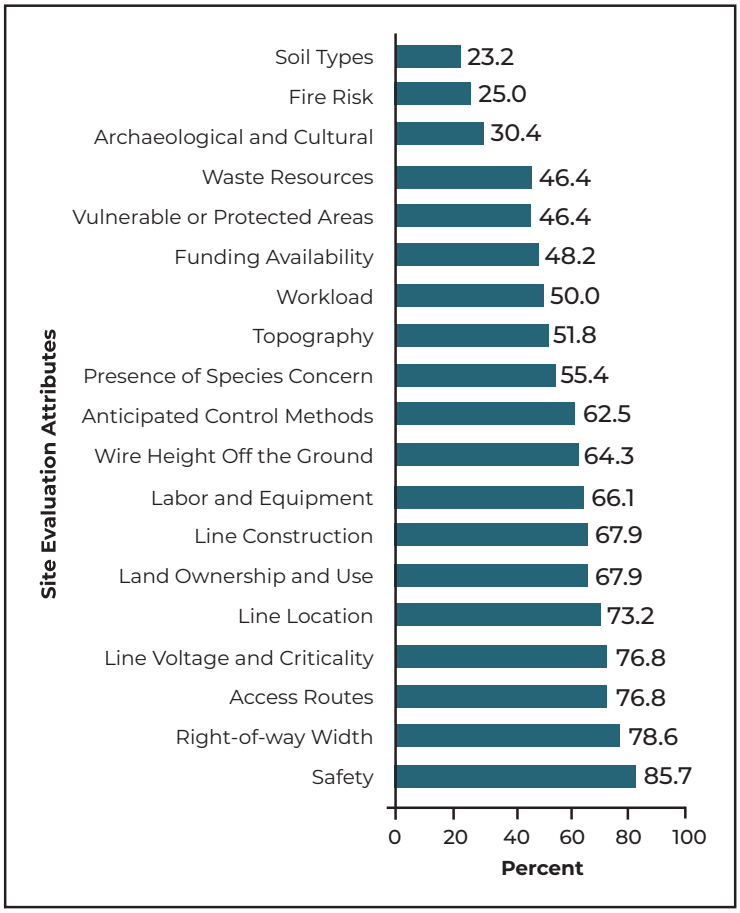


Figure 5-4. Site evaluations were part of IVM programs (n=56).

Action thresholds rather than a set time period are an integrated vegetation management best management practice. Action thresholds are vegetation height, density, location or condition targets that trigger control methods (Miller 2014). The idea is that vegetation management schedules should be determined by existing site and vegetative conditions rather than predetermined time intervals.

- IVM is based on a variety of methods. Physical (manual and mechanical) methods were most commonly used (4.75 mean index score). All respondents said it was important or very important. Chemical control was also important (4.36 mean index), followed by engineering (3.45), cultural (3.30), and biological methods (3.03).

The relatively low score for biological control methods (while still neutral) is consistent with the low priority on environmental stewardship and reinforces the need for more work to be done to increase awareness in that regard.

ANSI A300 Part 7 (ANSI 2018) advises that the reason for integrated vegetation management is to create, cultivate and conserve sustainable plant communities compatible with the site. In the case of electric utility lines, that often means converting from a tall-growing plant community to one comprised of plants that do not have the genetic predisposition to grow into the facilities. This process is called cover type conversion and it ultimately matures into a biological control (Miller and Kempter 2018). The comparatively low rating for biological control indicates that the most recent ANSI A300 Part 7 has not yet established common use in the industry.

- Closed chain of custody was used by less than half (45.0%) of responding utilities. There is a closed chain of custody BMP from the UAA, published by ISA (Goodfellow and Holt 2011).

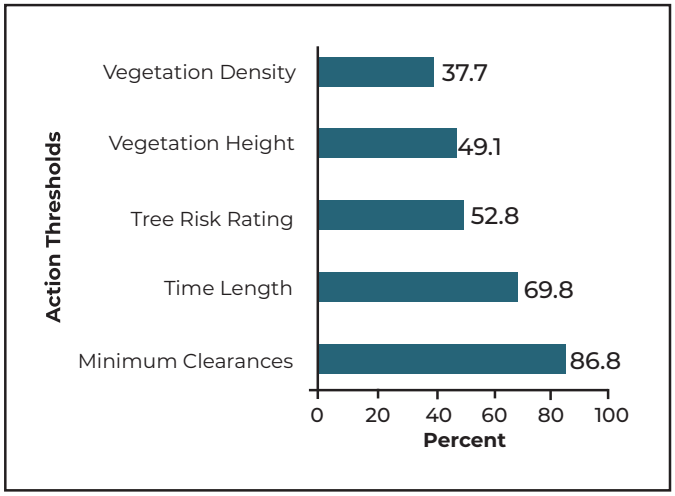


Figure 5-5. Action threshold used in decision making (n=53).

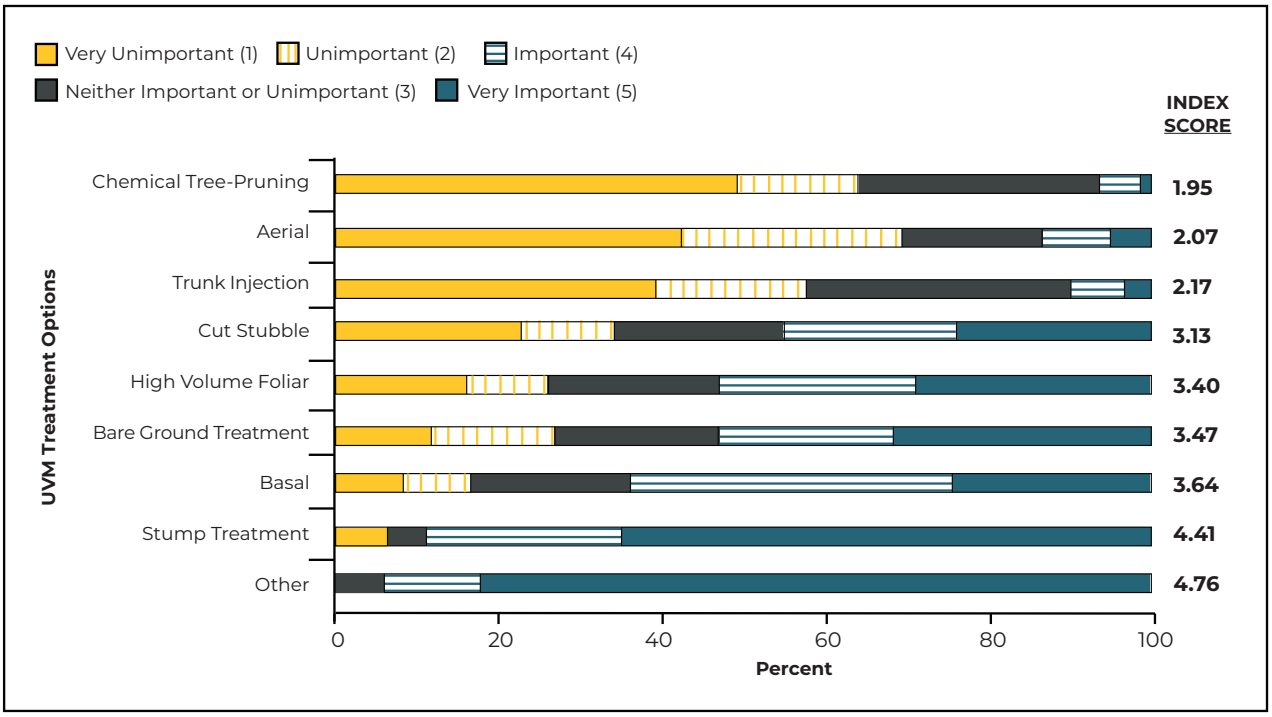


Figure 5-6. The importance of treatment options to IVM programs (n=59 to 61).

Closed chain of custody involves containers that are used, returned to the supplier for refilling in computerized facilities, and distributed for reuse. It requires closed connections when chemicals are transferred, creating a tracking system and auditable record. It is an advance that reduces the likelihood of errors in mixing, spills and the need for triple rinsing and container disposal.

- Relating to chemical treatment options, a significant number of utilities self-reported that low volume foliar spray treatment (4.76 mean index score) rated as most important. Stump treatment (4.41) was rated as very important (Figure 5-6). Chemical tree-pruning (1.95), aerial application (2.07) and trunk injection (2.17) were unimportant methods.
- Mechanical pruning using helicopters (equipped with an array of circular saw heads slung underneath) and ground machines (that have a circular saw on a extending boom) were common, 64.3% used this approach. Of those respondents a mean 17.6% (2.8 SE) of the total UVM budget was used for mechanical pruning.

The advantage of mechanical pruning is that it is significantly less expensive than what can be achieved by traditional tree crews. The disadvantage is that it is difficult to hit natural pruning targets with ground machines and impossible with helicopters. Consequently, ANSI A300 Part 1 (ANSI 2017) requires that, outside of emergency situations, mechanical pruning shall only be performed in remote or rural locations away from homes.

- Most cultural control methods were unimportant or recorded as neither important nor unimportant (Figure 5-7). Wire-border zone management (3.39), cover type conversion (3.15), and planting of seed compatible plants (3.07) were highest ranked.
- Overall, responding utilities were neutral on engineering solutions for their UVM program (Figure 5-8). Underground construction (3.27) of lines and moving poles or lines (3.21) were ranked highest. Wire-border zone (3.06), rising poles (3.02) and alley arms (2.98) were options with intermediate importance.
- Few utilities (25.7%) use tree growth regulators (TGRs). Of those that did, soil injection (57.1%) was most common followed by soil drench (8.1%). Trunk injection (9.5%) was uncommon. Only one utility (4.8%) used more than one option (soil injection and soil drench). The remainder of respondents indicated they only use one approach. Overall, the importance of TGRs was mixed. 55.0% said they are somewhat important and no utility responded it was very important. 40.0% said they are unimportant, 30.0% stated somewhat unimportant and 10.0% said TGRs are very unimportant.

The chemical effect of TGRs results in retarding tree growth. Responses suggest utilities are unenthusiastic about their use. Their history might provide insight into why. The first large scale use of TGRs in the 1970s involved methyl or isopropyl alcohol as carriers, which caused cracks, weeping from trunk injection sites and internal wood discoloration. The resulting widespread tree damage discredited TGR use among utility arborists (Chaney 2005). Perhaps they have not recovered from their early failure. Yet, by reducing growth of some species, tree growth regulators have been demonstrated to increase safety and tree health and reduce cost for utilities (Watson 2018).

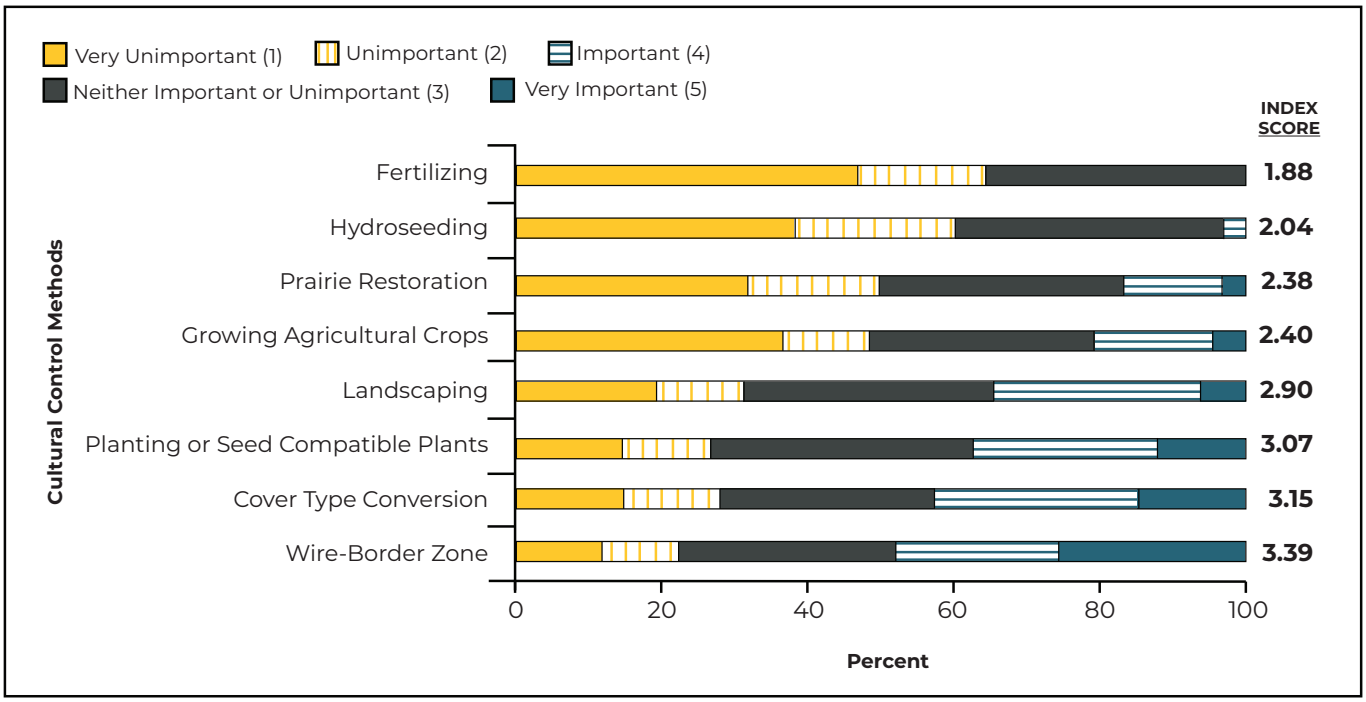


Figure 5-7. The importance of cultural control options to IVM programs (n=66 to 68).

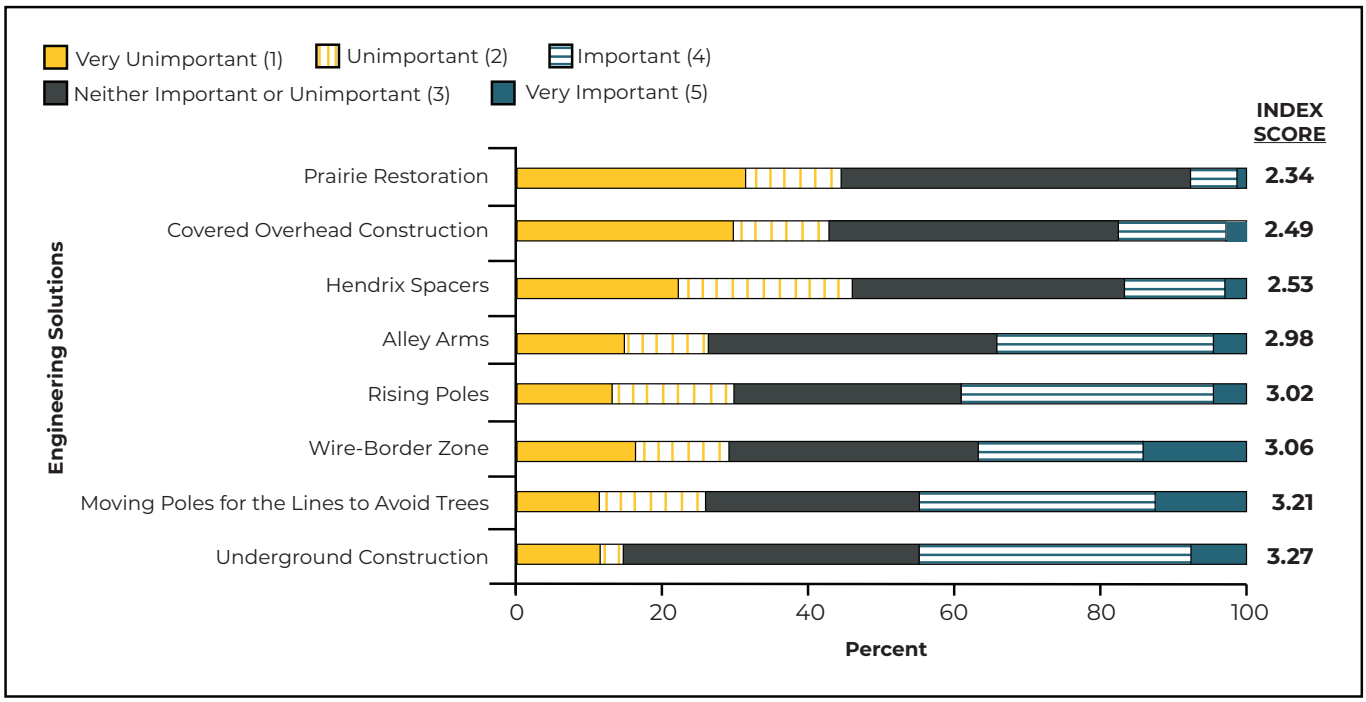


Figure 5-8. The importance of engineering solutions to IVM programs (n=59 to 62).

SECTION VI - ELECTRICAL OPERATIONS

This section covers electrical operations. Metrics used to describe system reliability was collected. The total percent of outages and total customer minutes of outages was reported. Respondents also described protective strategies to reduce vegetation-caused outages. Lastly, respondents reported on the percentage of outages caused by vegetation.

Key findings include:

- Responding utilities reported on their vegetation caused outages (Figure 6-1). The percentage of outages was lowest for transmission lines. A mean 1.1% (0.5 SE) of total outages and a mean 1.2% (0.7 SE) of total customer minutes were identified as vegetation related. Subtransmission lines were slightly higher with a mean 2.0% (0.9 SE) of total outages and mean 3.8% (1.7 SE) of total customer minutes identified as vegetation related. Distribution outages were a magnitude higher. A mean 23.2% (2.6 SE) of total outages and 21.7% (3.1 SE) of total customer minutes were identified as vegetation related.

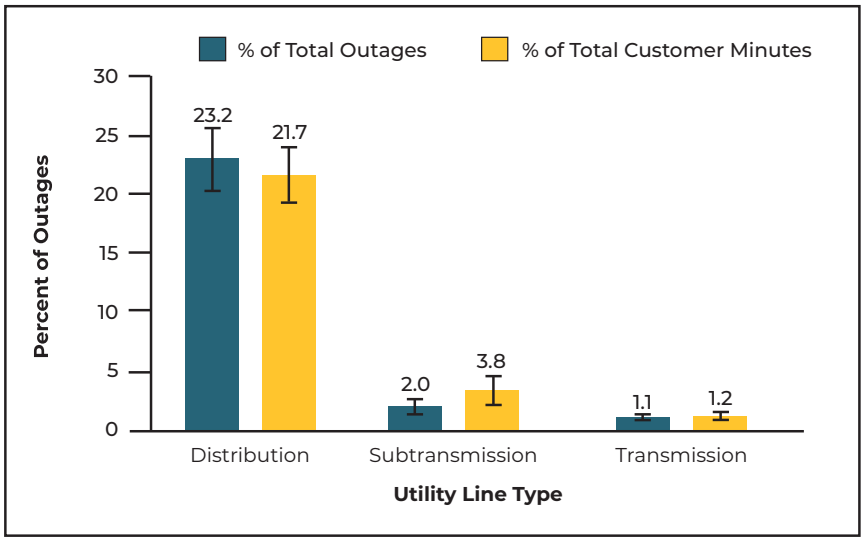


Figure 6-1. The percentage of outages caused by vegetation by line type (n=61).

Vegetation related outages are typically significantly lower for transmission than distribution lines for a number of reasons. First, many transmission lines are subject to FAC-003 under the auspices of FERC with the intent of preventing cascading outages of the transmission grid initiated by vegetation. It carries potential fines of $1 million a day for each violation. The standard has had a dramatic effect in improving reliability on the transmission grid.

Subtransmission vegetation-related outages are twice the proportion they are on transmission lines, but still far fewer than on the distribution system of responding utilities—subtransmission outages were reported at one-tenth of distribution system outages. While subtransmission is not subject to FAC-003, successful control of vegetation-related outages likely resulted from lessons learned from the transmission standard compliance. Secondly, utilities are aware an outage on a subtransmission or transmission line can have consequences a magnitude of order greater than that on distribution, so they have a vested interest in proactively managing those lines.


Photo Credit: Russel Evans


Photo Credit: Joshua Salas

Finally, transmission rights-of-way are often much wider than those for distribution lines, which lends itself to cover type conversion and compatible, low-growing plant communities.

- Reliability is an aspect of UVM strategy for most (95.8%) responding utilities.
- Distribution fuse coordination is a strategy for mitigating vegetation-caused reliability with nearly half (47.6%) of responding utilities.
- The System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) were important reliability metrics and had mean index scores 4.37, 4.36 and 4.21 respectively.
- Expanding pruning clearances at time of work was the highest ranked protective strategy with a mean 3.95 index score (Figure 6-2). Greater action thresholds (3.87) and greater tolerance levels (3.27) for three-phase lines were used. Shorter cycles for three-phase lines (3.20) was the lowest ranked protective strategy.

Note that this result is consistent with those presented earlier indicating that only one-third of responding utilities have different strategies for single and three-phase lines.

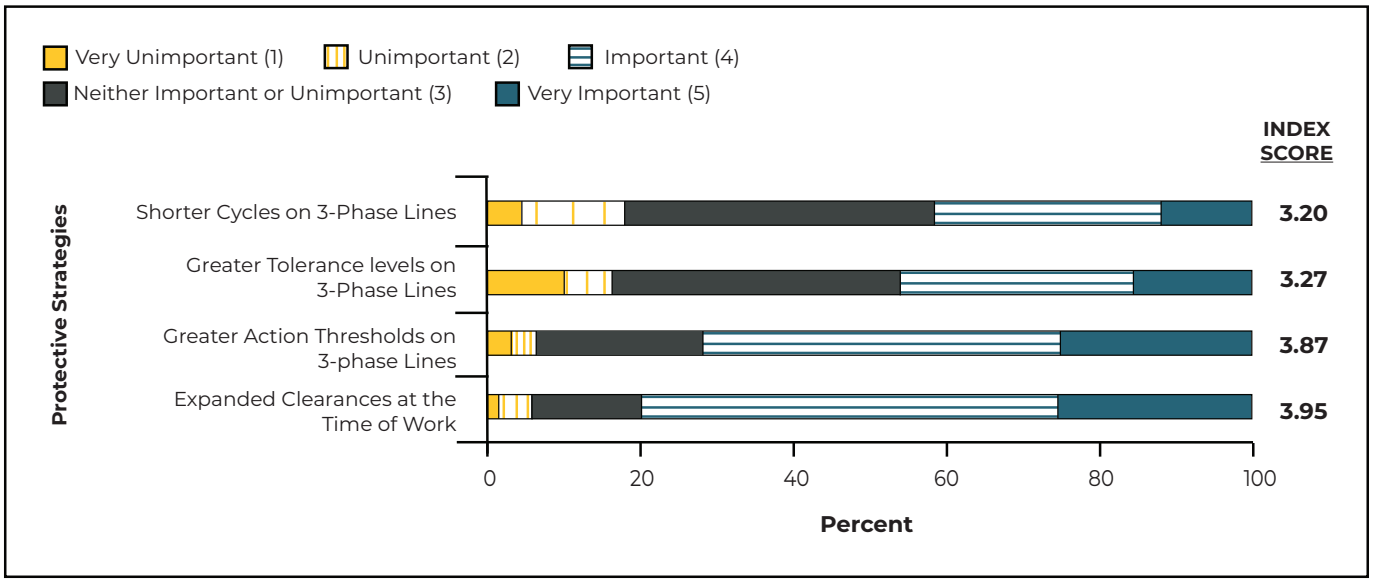


Figure 6-2. The importance of protective strategies to electrical operations (n=63 to 64).

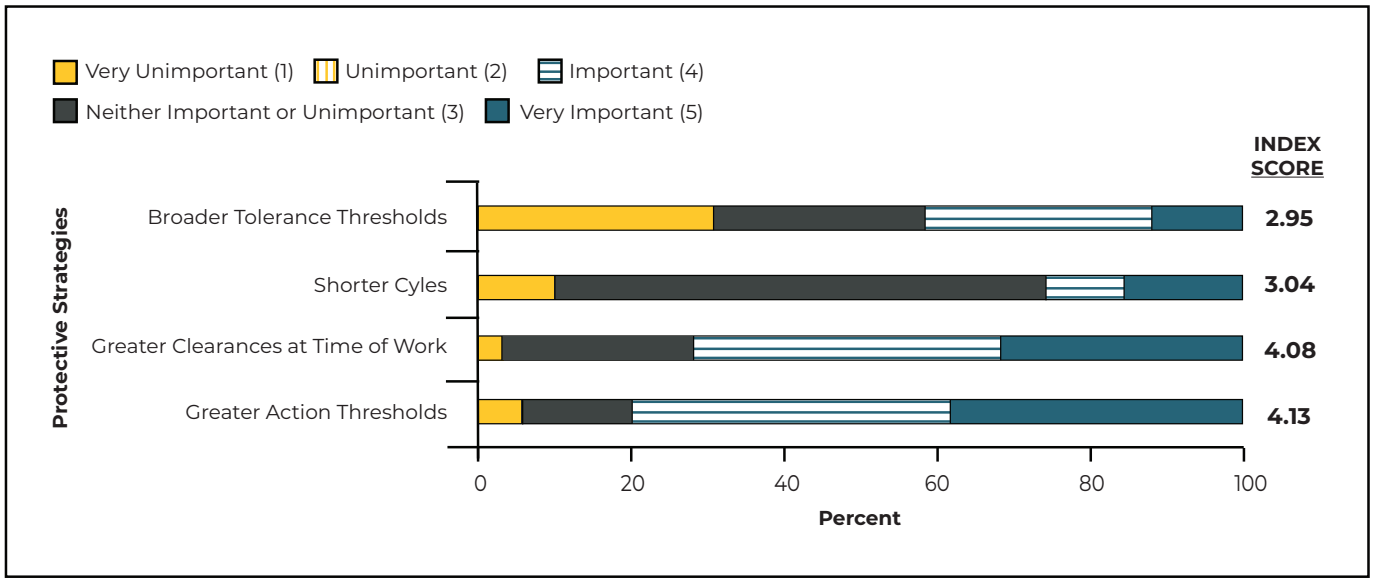


Figure 6-3. The importance of protective strategies to three-phase lines compared to single-phase lines to electrical operations (n=22 to 23).

- Utilities tend to have the same strategies for single and three-phase lines. Only 35.8% reported having different strategies for each.

A significant minority of utilities have adopted separate maintenance strategies for single and three-phase distribution lines. Their justification is that three-phase lines are more vulnerable to outages than single-phase lines (Reese et al., 2010). Electrical vegetation-caused outages occur due to either mechanical tear-down or short circuit. Mechanical tear-down is caused by tree parts or whole trees failing and damaging electrical facilities and is the most common cause of outage. Vegetation-caused short circuits occur when branches contact two phases, a phase and a neutral, or a phase and another conductive object.

Experimental work by Russell in 2011 established that a voltage gradient of roughly 2 kV per foot (6.6 kV per meter) is necessary for vegetation to cause an outage. Single-phase distribution lines are seldom sufficiently close to the neutral to build to the gradient threshold necessary to cause an outage. However, three-phase lines are often spaced sufficiently close and energized to a level that will develop a 2 kV per foot voltage gradient. For example, common spacing on three-phase lines is four feet (1.2 m), and they are often energized at 12.7 kV phase-to-phase. A branch laying across two such phases can result in a voltage gradient of more than 3 kV per foot (9.84 kV per meter), making an outage likely. By contrast, single-phase lines can be energized at 7.6 kV and have 6 feet (1.8 m) to a neutral. A branch contacting such a single-phase line and the neutral would have a voltage gradient of only 1.3 kV per foot (4.2 kV per meter), which is inadequate to generate a short circuit. This explains why some utilities that emphasize reliability (perhaps at the expense of safety) have different strategies for single and three-phase distribution lines.

- Each UVM strategy provides a method to decrease vegetation related outages. Responding utilities favored the importance of greater action thresholds (4.13) and clearances on three-phase than single-phase lines. Shorter cycles (3.04) and broader tolerance thresholds (2.95) were less important (Figure 6-3).
- Knowing how vegetation causes an outage provides valuable data to implement management methods to minimize future conflicts (Figure 6-4). The two most frequent vegetation-related outages, explaining over 60.0% of all causes, were off right-of-way trees (34.4%, 4.1 SE) and whole tree failure (27.2%, 3.7 SE). Broken branches explained 19.4% (2.6 SE) of vegetation related outages. Grow-ins (11.4%, 2.4 SE) and overhang (6.0%, 1.4 SE), while not unimportant, were the lowest identified reasons. Vines were identified as a self-reported other cause and collectively account for 0.26% of outages.

These results are consistent with observations by Russell (2011) and others that most outages are caused by off right-of-way trees. It emphasizes the importance of tree risk assessment programs in UVM.

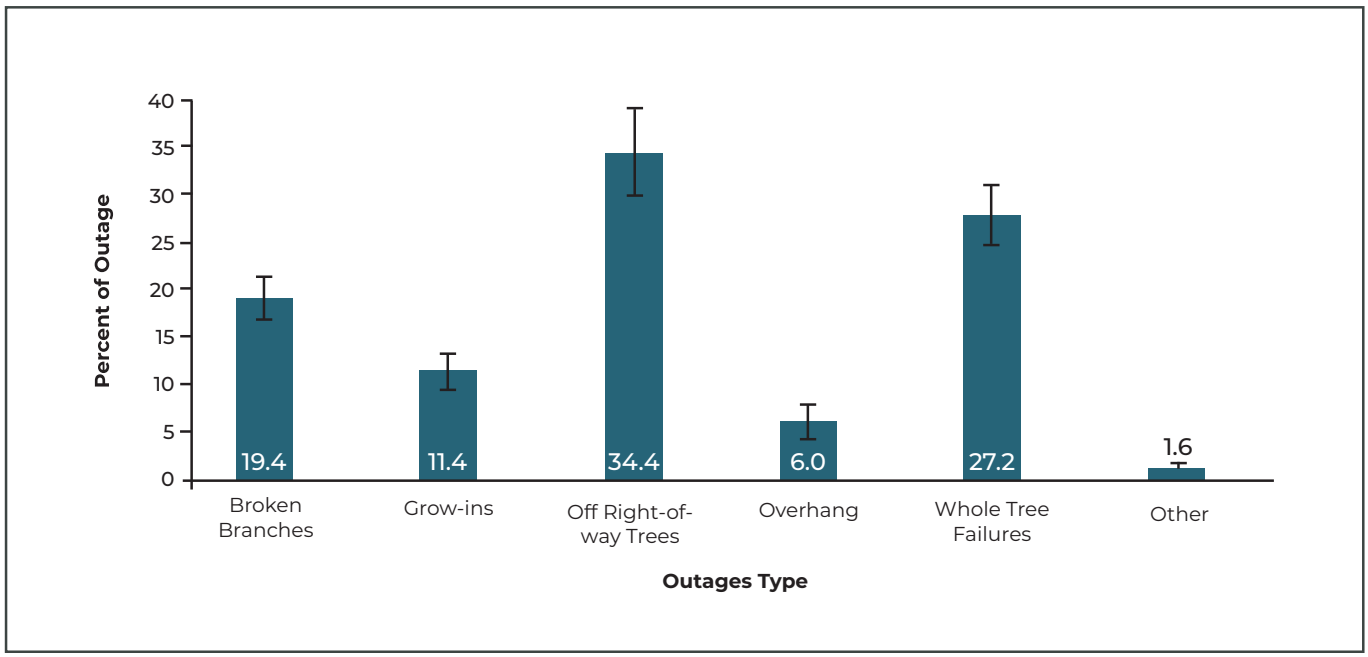


Figure 6-4. The percentage of vegetation-related outages caused by outage types (n=53).

SECTION VII – STORM RESPONSE

Section VII covers storm response by utilities. The survey investigated how utilities respond to storms and storm debris. It inquired whether utilities have a storm response protocol that triggers a response and if so, what criteria is used to initiate. The survey asked utilities if a storm declaration affects overtime pay and if storm response work is capped.

Utilities explained who declares a storm emergency and the criteria used to declare the storm emergency. The survey determined whether the communications department staff are involved in the storm response and how important pre-approved messages are for tree crews. Finally, respondents reported which production data they collect during storms.

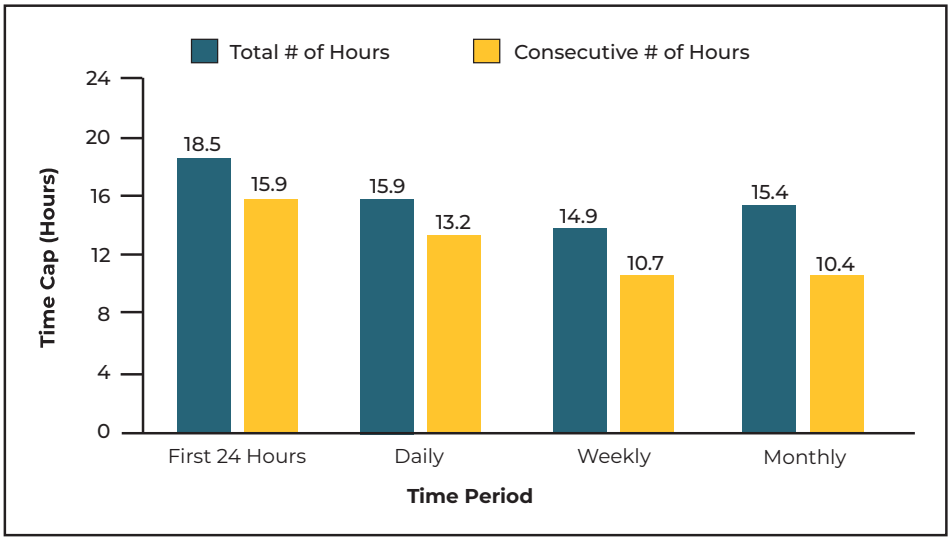


Figure 7-1. What strategy do you use to cap hours for the following time periods (n=5 to 26)?

Key findings include:

- The use of a storm response declaration protocol is very common, implemented by 92.9% of responding utilities.
- A storm response declaration affects how storm responders are paid (e.g., trigger overtime) in approximately half (52.5%) of utilities.
- 63.3% of utilities capped hours worked during storms. Capping of time varied with length of storm response (Figure 7-1). Responders were allowed to work longer



(total time and consecutive hours) during the first 24 hours versus over a longer period (weekly or monthly). During the first 24 hours a mean 18.5 (0.7 SE) total hours with 15.9 (1.4 SE) hours allowed consecutively. During storm events that last several days or longer (e.g., week, months), total hours worked in a day were capped at 15 to 16. The consecutive amount of time worked was capped at approximately 10 to 11 hours for events lasting a week or longer.

- Many factors were identified as important to very important in storm response (Figure 7-2). By far, safety was nearly unanimously rated (4.96) as a very important factor. Electrical hazard communication protocol (4.57), supervision (4.56), fatigue (4.55) and wood under tension (4.46) were also rated as important and very important factors. Animals and insects (2.74) and equipment rental (2.88), while not considered unimportant, were rated lowest.
- Utilities provided insight into the criteria they used to declare a storm emergency (Figure 7-3). The number of customers out of power was the most common (92.2%) criteria cited. Extent of infrastructure damage (81.3%), percent of customers without power (56.3%), duration of storm (43.8%) and number of interruptions (42.2%) were also important.

Storm preparedness involves developing a set of processes and operations prior to a storm so the response goes as well as can be expected (Miller and Kempter 2018).

- Respondents ranked having an emergency response center (4.31) as the highest storm preparation strategy (Figure 7-4). Also important was having pre-storm communication checks (4.17) and an incident command system (4.16) in place. In advance of storms developing, pre-mobilization systems or agreements (3.86), coordination with local government (3.73) and storm practice drills (3.66) were important for storm preparedness.

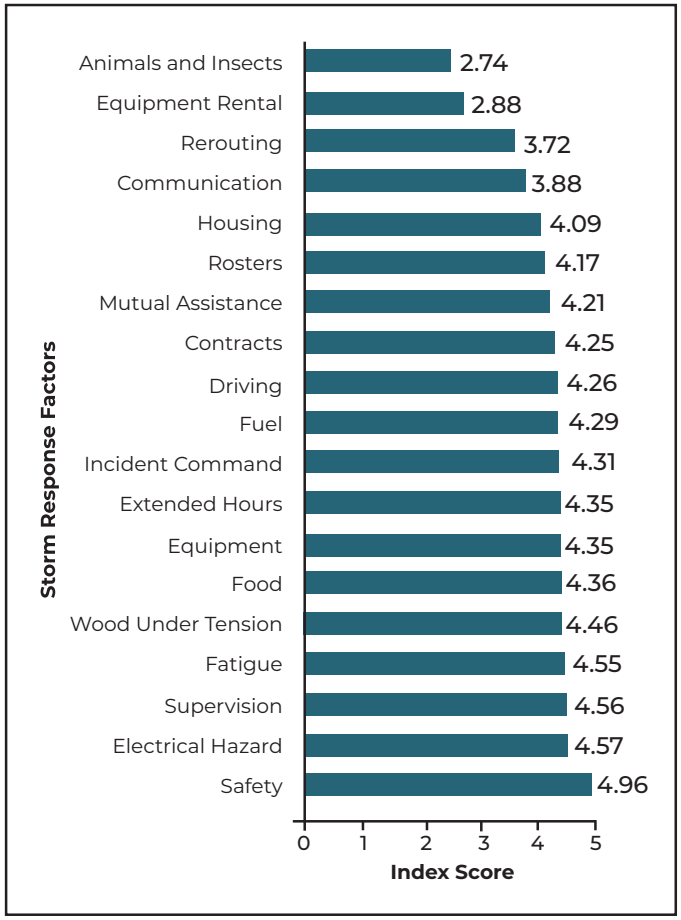


Figure 7-2. The importance of storm response factors (n=65 to 69).

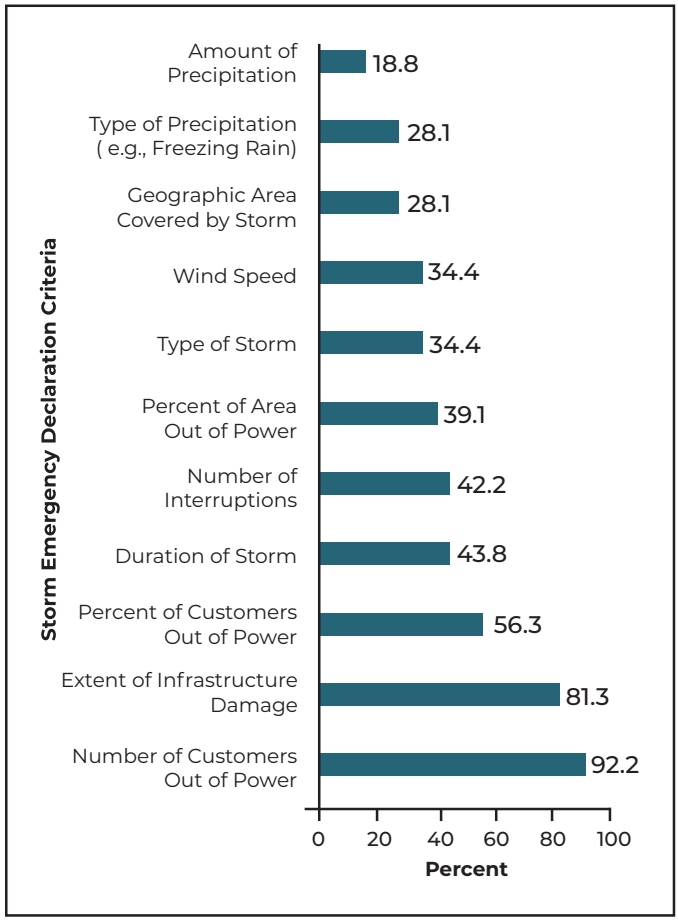


Figure 7-3. Criteria used to declare a storm emergency (n=64).

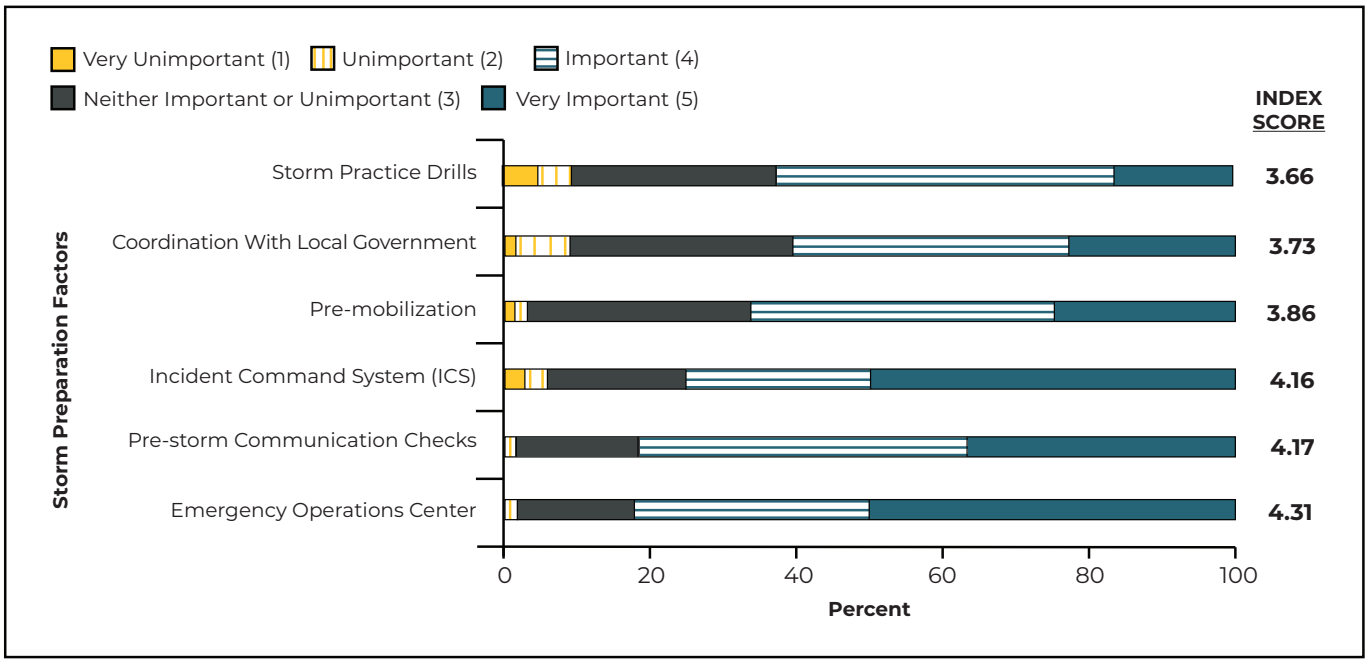


Figure 7-4. How important are the following storm preparation factors in your vegetation management storm response (n=65 to 68)?

- Appointing an official who declares a storm emergency is standard practice. More than one person may be part of this process, however, 64.6% of utilities indicated one person made the declaration. An operations leader is part of appointing the decision nearly 80.0% of the time, as either the operations manager (40.0%) or operations director (38.5%). A storm response committee was part of the decision 26.2% of the time. The president (20.0%) or vice-president (20.0%) were involved, but to a lesser degree. These senior level positions were likely to be part of the decision-making group 62.5% of the time.
- Collecting production data during a storm response is one of many important functions. Only half of responding utilities (50.7%) reported collecting production data during storm response, compared to nearly all (97.1%) doing so during normal operations. Data collected during storms most included hours worked (94.3%) and locations worked (71.4%) (Figure 7-5). Data collection pertaining to production was uncommon and reported as number of trees removed (25.7%), square area (11.4%), and loads or cubic volume (8.6%) of debris.
- A plan for storm debris, whether left on site, removed, or a combination approach is important to develop prior to storm response. Debris is left on site for 70.1% of responding utilities. A total 25.4% never leave debris from storms on site. Few (4.5%) utilities occasionally leave debris on site and for these utilities a mean 74.6% (7.3 SE) of debris is left on site.
- Involving communications departments may provide for timely and appropriate messages to customers (Miller and Kempter 2018) (Figure 7-6). Press releases on the extent of outages (77.4%) and communicating estimated time of restoration (71.0%) were most common as media approaches. 59.7% said media relations control 100.0% of storm messaging. Further, 37.1% place restrictions on front line employee communications and 30.6% use a pre-approved message for tree crews (e.g., “we are working hard to get things back to normal”). Respondents were mixed with the importance of a pre-approved message with a mean 2.86 (0.15 SE) index score.

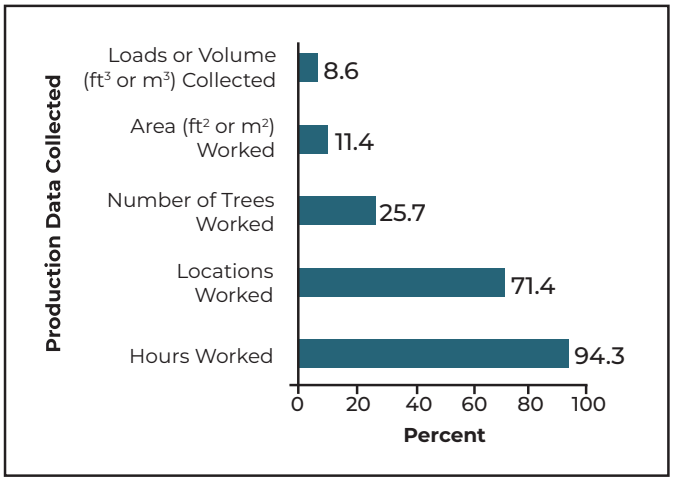


Figure 7-5. Production data collected during storms (n=35).

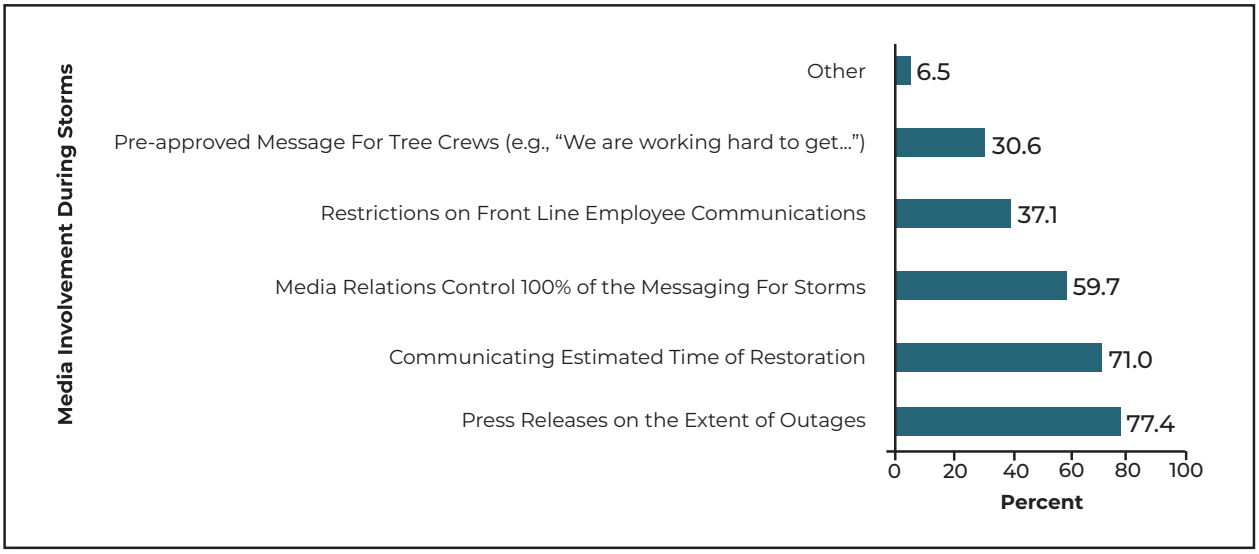


Figure 7-6. How is your communication department involved in storm response (n=62)?



SECTION VIII – COMMUNICATIONS

Communication in advance of an action and keeping customers informed are best management strategies to increase service satisfaction. Respondents provided information on how they communicate to customers before work. For example, the questionnaire inquired whether utilities used customer satisfaction surveys to evaluate work. Respondents ranked the importance of outside groups as well as the importance of a variety of communication types.

- Utilities use a variety of ways to communicate with customers before work occurs. Most (71.4%) use two or more methods. Utilities may use contract (55.7%) or in-house (57.1%) utility foresters/arborists to communicate with customers prior to work occurring. Most often (82.9%), a person was involved with communicating with customers (in-person or providing materials) and this contact was mixed with approximately one-third using contract, in-house, or both to do such. Tree crews were an important frontline communication approach, used by 50.0% of utilities. Other self-reported (35.7%) methods used include indirect contact. Direct mail (14.3%), phone message (14.3%) or door hangers (8.6%) were used. These percentages are reflective of the total response.
- Customer satisfaction surveys provide information to reflect how well operations are occurring and if changes are needed. Over half (54.3%) of respondents said they use customer satisfaction surveys. Phone call (43.2%) and website directed surveys (40.5%) were most common (Figure 8-1). Door hangers (27.0%) or follow-up visits (8.1%) were less commonly used.
- Groups external to a UVM program can provide communication messages about utility operations (Figure 8-2). Residential customers (4.48), property owners (4.42) and UVM contractors (4.41) were the three most important groups. They are most closely tied to where work occurs, so their importance is not surprising. Interestingly, the media (3.77) was considered of intermediate importance.
- Respondents were asked to rank the importance of five types of communication. Using a scale of 1 (least important) to 5 (most important), town hall meetings (2.30) and e-mail messages/blasts (2.51) were considered least important for UVM communication. Brochures (3.57) and social media (3.45) were ranked highest and press releases (2.86) of intermediate importance. A take home message is that although a variety of approaches are used, some rank higher than others, but in general, communication plans are highly individual and what works best for some operations might not work best for another utility.

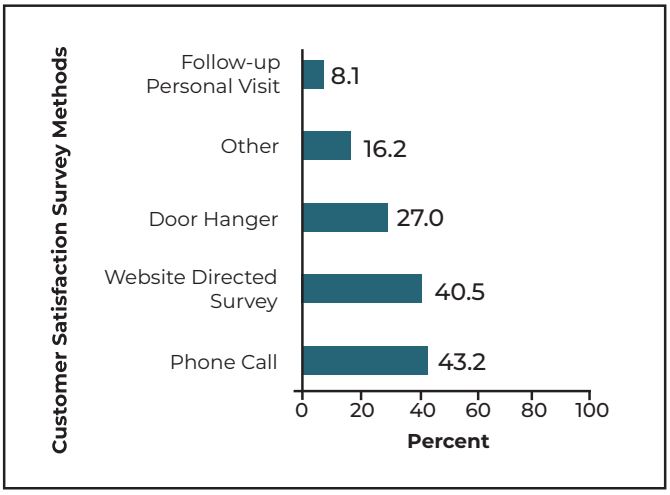


Figure 8-1. How do you conduct customer satisfaction surveys (n=37)?


Photo Credit: Iarn McCulley

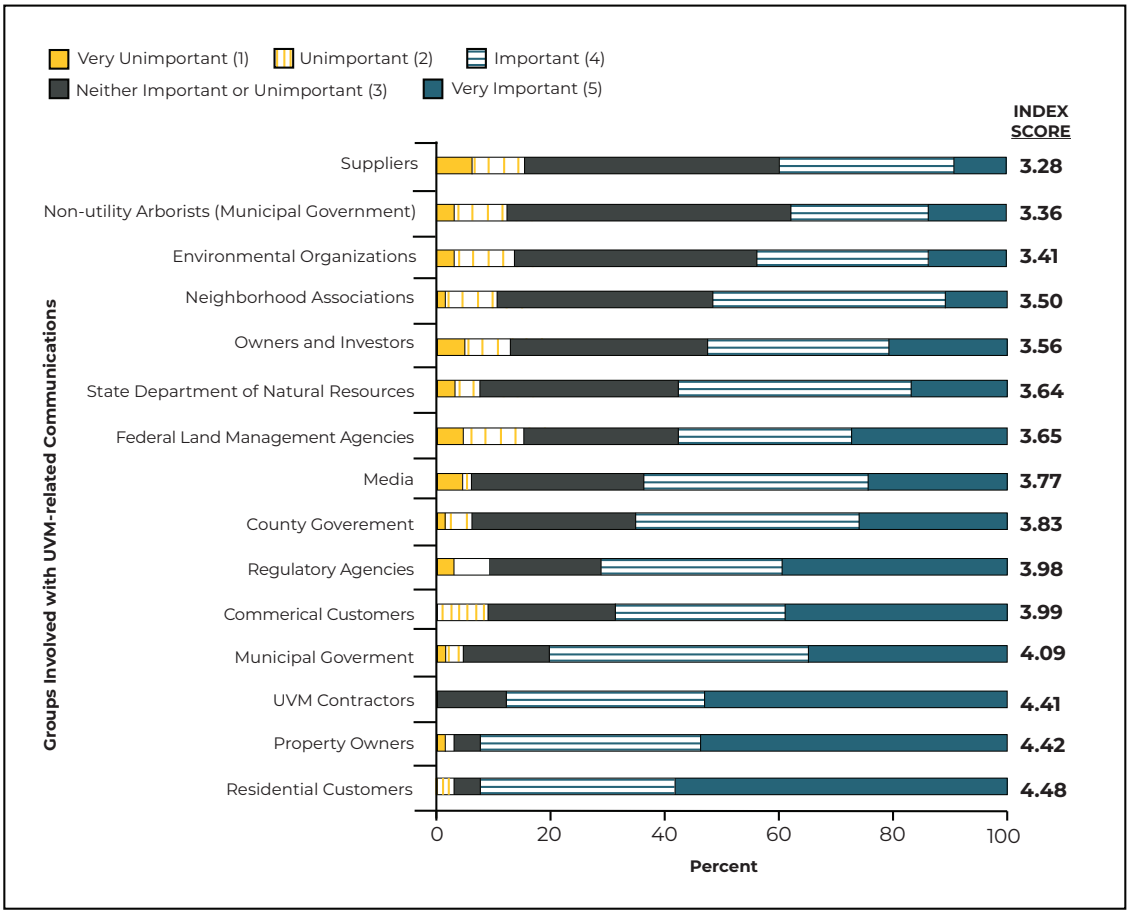


Figure 8-2. The importance of the following groups for UVM-related communications of utility operations (outside of UVM, n=63 to 68).

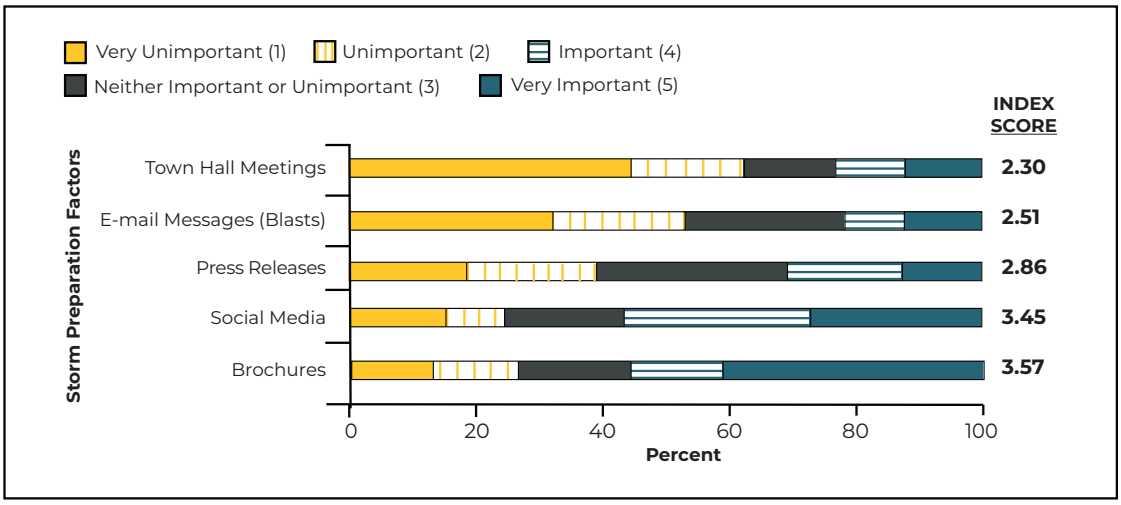


Figure 8-3 The importance of the following types of communication you use for UVM (1 = very unimportant to 5= very important, n=63 to 67).

CONCLUSIONS

The 2019 Utilities & Vegetation Management in North America report© describes the current state of utility forestry tree activities and operations. This study drew from a list of 210 utilities from a historical CNUC list and Tree Line USA® recipients from the Arbor Day Foundation. 71 responding utilities covered over 52 million customers, 107,000 miles of transmission, nearly 80,000 miles of subtransmission and 1.1 million miles of distribution lines. It solicited answers to questions covering UVM programs that require command of safety, program management, pruning, IVM, electrical operations, storm response and communications.

Important findings show 97.0% of responding UVM programs learn from safety incidents, but they were not enthusiastic on UAA Safety Summits.

Nearly 80.0% of responding utilities had centralized UVM programs, the majority of which had a department head with a natural resource degree. Over 21.0% of trees were in contact with distribution lines at the time of work. Safety and service reliability were the prominent reasons responding utilities used for UVM, while 23.2% of outages and 21.7% of lost customer minutes were attributable to vegetation. Emergency response centers were a prominent storm response strategy and safety was the most important consideration. UVM programs use contract, or in-house arborists to communicate with customers, commonly via brochures and social media for non-face-to-face communication. Follow-up surveys might focus on utility forest population and workload, productivity, and research and development.

We sincerely thank the many people vital to completing this project. We thank the initial group who reviewed the research instruments prior to its release. Ian Vierck and Emily Cleaver for the survey layout and database management. Questionnaire and final report editors Shannon Bussone-Rue and Katie Moehn and final report designer Megan Taylor. The UWSP Print Design staff were vital to the quality printing of the questionnaire and final report. And lastly, we thank all utilities that participated and provided their valuable time to share their current UVM programs.



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APPENDIX A: QUESTIONNAIRE & RESULTS

Thank you for participating in the 2019 utility vegetation management survey jointly conducted by CNUC and the University of Wisconsin – Stevens Point (UWSP). It is the latest iteration of benchmarking surveys CNUC has conducted since 2002. This survey is intended for the person(s) who can best tell us about your utility operation and utility vegetation management (UVM). Ideally, the person directly responsible for your program will respond, however, any utility employee who can best respond, to any question, should do so. Answer each question the best you can. If multiple departments/groups are involved with your utility, we ask that the entire program be formulated as one response using this questionnaire. It is important to answer as many applicable questions as possible.

Please read each question carefully: Respond to each question with the answer that best fits your utility. An example follows below.

1. Does your utility conduct utility vegetation management?

   (CHECK ONE)
   ☐ Yes
   ☐ No

Please try to answer every question that applies to you. If none of the answers provided seem exactly right, choose the one that best reflects what occurs in your utility. If you are unable to answer any question, leaving it blank is acceptable.

The data from each participating utility is pooled together and shared, without identifying any responding utility. The intent is to enable industry professionals to compare and contrast their program with their peer North American utilities. The ultimate objective of this benchmark study is to further develop an understanding of utility arboriculture, advance the profession, and help utility vegetation managers improve their programs. The results of the survey will be submitted for publication in Arboriculture and Urban Forestry, the Utility Arborist Newsline, and other periodicals.

Each participating utility will be randomly assigned a discreet three-character numeric identifier, to which responses will be exclusively attributed. Codes are changed for each survey to enhance security. Participating utilities will be informed of their individual code. Only the subject utility and the CNUC director of research and development and the cooperating University of Wisconsin – Stevens Point research team will know the codes assigned to specific respondents. Exceptions will only be made at a participating utility's written permission or request.

ABBREVIATIONS/DEFINITIONS

n= number of respondents for a question
SE= standard error of the mean

SECTION I – COMPANY PROFILE

1. How many total customers does your company serve? n=69

756,600 (mean), 3500 to 7,752,009 (range) # of total customers

2. What type of business is your utility? n=71

(CHECK ALL THAT APPLY)

97.2% Distribution
69.0% Transmission
45.1% Generation

3. What is your ownership structure? n=74 (note 1 was both Federal and municipal owned and 1 was both investor owned and state/provincial owned)

(CHECK ALL THAT APPLY)

20.3% Cooperative
1.4% Federal
37.8% Investor-owned utility
31.1% Municipal/public utility district
6.8% State/provincial
2.7% Other: (2 responses: Authority; Owned by the states DU's)

4. What distance (km or mi) of overhead lines do you have on your system and specify the unit metric used to measure line distance? n=71

Units are in: (CHECK ONE)

☐ km (kilometers)
☐ mi (miles)

Line Distance *(all units below expressed in miles)*
(Please enter "0" if none.)

Mean (mi)	Range (mi)	SE[1] (mi)	Line Type
2,999	9 to 31,000	963	Transmission (e.g., 200K line, subject to FAC-003-4)
1,936	6 to 11,127	401	Sub-transmission (e.g., local, not subject to FAC-003-4)
16,523	5 to 130,120	3,514	Distribution
3,322	25 to 32,000	1,702	Secondary
18,778	5 to 130,120	4,478	Primary
8,104	5 to 48,000	1,961	Three-phase[2]
13,429	0 to 83,292	3,415	Single-phase[2]

66.8 (mean, 3.0 SE), 6 to 100 (range) % of primary lines accessible by aerial lift (e.g., truck, backyard, skidder)

[1] SE = Standard Error of the Mean throughout report

[2] Primary = Three-phase and Single-phase

SECTION II – SAFETY

1. How important are the results of Utility Arborist Association (UAA) Safety Summits to your program? n=65

13.8% Very unimportant
16.9% Somewhat unimportant
30.8% Neither unimportant or important
23.1% Somewhat important
15.4% Very important

3.09 (mean, 0.16 SE, 1= very unimportant and 5= very important)

2. Does your company use a third-party safety administrator (such as ISNetworld)? n=68

(CHECK ONE)
29.4% Yes
70.6% No

3. Are unintentional safety errors subject to progressive discipline? n=63

(CHECK ONE)
44.4% Yes
55.6% No

4. Is intentional safety misconduct subject to progressive discipline? n=63

(CHECK ONE)
95.2% Yes
4.8% No

5. Are close calls (near misses) reported? n=70

(CHECK ONE)
97.1% Yes
2.9% No

6. Are lessons learned communicated to others in the organization? n=66

(CHECK ONE)
97.0% Yes
3.0% No → (PLEASE GO TO QUESTION 8)

If yes, please explain: _____

7**. How are lessons learned communicated to others in the organization? n=64**

(CHECK ALL THAT APPLY)

28.1% Department-wide conference call
56.3% Job briefing
89.1% Safety meeting
65.6% Safety stand-down
25.0% Other: (16 responses)
e-mail (10 responses, 15.6%)
Safety bulletin/report (4 responses, 6.3%)

8. Does your department have a safety committee(s)? n=71

(CHECK ONE)

67.6% Yes
32.4% No → (PLEASE GO TO QUESTION 13)

9. How many times a year does your safety committee meet? n=41

10.61 (mean)

1 to 52 (range)

12 (65.9%) most common # of times

10. Please rate the importance of each subject area to your safety committee. n=46

Subject Area (% of total & mean)	**Very Unimportant (1)**	**Unimportant (2)**	**Neither Important or Unimportant (3)**	**Important (4)**	**Very Important (5)**	**Mean Index Score**
Assisting in incident investigations	2.2	0.0	13.0	30.4	54.3	4.35
Developing training	2.2	0.0	13.0	43.5	41.3	4.22
Establishing procedures	2.2	0.0	10.9	41.3	45.7	4.28
Evaluating procedures	2.2	0.0	6.5	43.5	47.8	4.35
Evaluating safety training and educational material	2.2	0.0	17.4	39.1	41.3	4.17
Identifying high-risk tasks	2.2	0.0	6.5	23.9	67.4	4.54
Monitoring safety performance	2.2	2.2	0.0	45.7	50.0	4.39
Tracking progress	2.2	2.2	13.0	32.6	50.0	4.26
Other: 1 response, committee identifies issues work to address	-	-	-	-	-	-

11. Who currently chairs the safety committee? n=42

(CHECK ONE)

92.9% Company utility representative
0.0% Contract manager
0.0% Contract general foreperson/supervisor
0.0% Tree crew leader
0.0% Tree crew member
7.1% Other: (3 responses: Combination of people)

12. Is the safety committee(s) empowered to contribute to departmental safety policy? n=42

(CHECK ONE)

100.0% Yes
0.0% No

13. Is contractor safety training allowed during billed working hours? n=68

(CHECK ONE)

67.6% Yes
32.4% No → (PLEASE GO TO QUESTION 15)

14. How many times per year is contractor safety training allowed during billed working hours? n=26

10.12 (mean), 1 to 52 (range), 12 (26.9%) most common # of times

15. What is the importance of the following safety authorities to your program? n=69 to 70

Subject Area (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
ANSI Z133 (2017 version)	7.1	1.4	1.4	15.7	74.3	4.54
Contractor safety policy	4.3	0.0	4.3	18.8	72.5	4.39
OSHA/OHS Canada	7.2	0.0	4.3	21.7	66.7	4.35
State/provincial requirements	2.9	0.0	13.0	24.6	59.4	4.35
Utility company safety policy	2.9	0.0	5.8	10.1	81.2	4.28

16. How many OSHA/OHS Canada recordable safety incidents have occurred by working group in the past three years (enter "0" if no incident)? n=43 to 52, (mean value and (SE) reported in table)

Working Group	2016	2017	2018
In-house staff	0.77 (0.71)	0.92 (0.86)	0.90 (0.75)
Vegetation management contractor	2.65 (0.83)	2.72 (0.76)	3.15 (1.08)
Consulting arborist	0.002 (0.02)	0.0 (0)	0.02 (0.02)

17. Do you calculate OSHA accident rates (DART: Days Away, Restricted or Transferred, per 100 employees per year)? n=58

(CHECK ONE)

56.9% Yes

43.1% No → (PLEASE GO TO QUESTION 19)

If yes, please explain how you apply it to your safety program: _____

_____

_____

_____

_____

_____

_____

18. On average, what is your annual DART rate (per 100 employees per year) over the past 3 years? n=18 to 23

(Please enter "0" if none)

0.23 (mean), 0 to 2.06 (range) In-house staff

0.51 (mean), 0 to 1.60 (range) Vegetation management contractor

0.00 (mean), 0 to 0 Consulting arborist (planning and quality assur.)

19. On average, how many public electrical contacts involving trees have occurred annually on your system over the past 3 years?

0.50 (mean, (0.19 SE), 0 to 5 (range), n=43: # of electrical contacts/year

20. On average, how many fires involving trees have occurred annually on your system over the past 3 years?

0.76 (mean, (0.47 SE), 0 to 25 (range), n=54: # of fires per year

SECTION III – PROGRAM MANAGEMENT

1. Which structure best characterizes your UVM program? n=69

(CHECK THE BEST DESCRIPTION)

79.7% Centralized into a single department

17.4% Centralized by program (e.g., distribution, transmission)

0.0% Decentralized
(e.g., operational units like regional district offices, each responsible for independent UVM programs)

2.9% Other: (2 responses: Contract, Centralized State Office)

2. Do you have a UVM department head? n=70

(CHECK ONE)

92.9% Yes

7.1% No → (PLEASE GO TO QUESTION 5)

3. What is your UVM department head's title? n=64

(CHECK ONE)

1.6% Arborist

14.1% Director of Vegetation Management

6.3% Forester

28.1% Manager of Vegetation Management

1.6% Operations Manager

1.6% Senior Utility Arborist

14.1% Supervisor of Vegetation Management

4.7% System Forester

28.1% Other: (18 responses)

Manager (7 responses, 10.9%)

Supervisor (3 responses, 4.7%)

Superintendent (3 responses, 4.7%)

4. What credentials does the UVM department head have? n=64

(CHECK ALL THAT APPLY)

82.5% ISA Certified Arborist

52.4% ISA Certified Arborist Utility Specialist

1.6% ISA Board Certified Master Arborist

20.6% ISA Tree Risk Assessment Qualification

49.2% Bachelor of Science in a natural resources related field
(e.g., agronomy, arboriculture, forestry, horticulture, urban forestry, wildlife biology)

6.3% Master of science in natural resource related field

0.0% PhD in natural resource related field

39.7% Other: (25 responses, no central theme, variety of answers)

5. In what department does UVM reside? n=66

(CHECK ONE)

1.5% Contract administration
6.1% Engineering
0.0% Finance
43.9% Operations
1.5% System reliability and maintenance
0.0% Technical services
33.3% Vegetation management
13.6% Other: (9 responses, operations and/or management)

6. How many total people work for your UVM program? n=68

215.1 (mean, 215.1 SE), 1 to 5320 (range), # of People

7. How many in-house UVM personnel or contractors work in your UVM program? Fill in the number of positions and Full Time Equivalents – FTEs, 2080 hours base year, enter "0" if no position.

Position Categories (mean values)	Number of Positions	Number of FTEs
Example Answer	*2*	*1.5*
General foreperson(s)/supervisors	15.58	16.97
Crew leaders	40.52	44.35
Planners	9.60	10.10
Tree care workers	156.51	174.38
Other: (_____)	33.83	29.59

8. How many UVM personnel are contractors in your UVM program? Fill in the number of positions and Full Time Equivalents – FTEs, 2080 hours base year, enter "0" if no position.

Position Categories	Number of Positions	Number of FTEs
Example Answer	*2*	*1.5*
General forepersons/supervisors		
Crew leaders		
Planners		
Tree care workers		
Other: (_____)		

9. What percentage of your total FTE's are directly responsible managing your UVM program? n=58

39.5 (mean, 5.6 SE), 0 to 100 (range) # of People

10. How many levels of management are involved in directing the UVM program?

(i.e., Utility CEO → Director of Vegetation Management → System Forester → Foreperson/supervisor → Crew Worker = 4 steps) n=63

4.8 (mean, 0.3 SE), 1 to 12 (range) # of levels

11. Is your UVM work pre-planned or inspected ahead of tree crews? n=69

(CHECK ONE)

89.9% Yes
10.1% No → (PLEASE GO TO QUESTION 13)

12. Who conducts your UVM work, pre-planned or inspected, ahead of tree crews? (Please enter "0" if none.) n=61

Who Conducts UVM Work	**% of total**
Example Answer	*32*
Company employees	39.1
Contract work planners	52.3
Tree crew members	5.3
Combinations	0.02
Other: *(3 responses: foreman, manager, supervisor)*	3.3
Total	**= 100%**

13. On what device(s) is vegetation management data collected? n=65

(CHECK ALL THAT APPLY)

36.9% Desktop computer
46.2% Laptop
38.5% Mobile phones
55.4% Paper
58.5% Tablets (PCs/iPad)
0.0% Other: (no responses)

14. Do you use GIS-based software for vegetation management planning? n=65

(CHECK ONE)

72.1% Yes
27.9% No

15. How is the work location identified? n=65

(CHECK ALL THAT APPLY)

70.8% Address
75.4% Circuit
41.5% GIS location
29.2% Grid or polygon
56.9% Pole number
41.5% Span
43.1% Tree/bush units to be worked on
6.2% Other: (4 responses: street name, service #, map, line name)

16. Do you keep track of the amount of work you accomplish? n=68

(CHECK ONE)

97.1% Yes
2.9% No → (PLEASE GO TO QUESTION 19)

17. Which distribution line production measurements do you track? n=61

(CHECK ALL THAT APPLY)

18.0% Area (ft^2 / m^2) of saplings (brush) pruned
39.3% Area (ft^2 / m^2) of saplings (brush) removed
37.7% Area (ft^2 / m^2) of saplings (brush) treated with herbicide
75.4% Distance (km or mi) of line cleared
8.2% Trees in contact with the line at the time of maintenance
31.1% Trees per mile / km worked
60.7% Trees pruned
75.4% Trees removed
9.8% Other: (6 responses: spans 6.6%)

18. Which transmission line production measurements do you track? n=44

(CHECK ALL THAT APPLY)

27.3% Area (Acres or ft^2 / hectare or m^2) of saplings (brush) pruned
59.1% Area (Acres or ft^2 / hectare or m^2) of saplings (brush) removed
68.2% Area (Acres or ft^2 / hectare or m^2) of saplings (brush) treated with herbicide
56.8% Trees pruned
70.5% Trees removed
25.0% Other: (11 responses: 7 described some distance)

19. Which industry affiliations does your UVM program have? n=65

(CHECK ALL THAT APPLY)

80.0% Arbor Day Foundation (Tree Line USA)
3.1% Energy for Wildlife
83.1% International Society of Arboriculture
6.2% The Nature Conservancy
1.5% Pesticide Environmental Stewardship Program
3.1% Pheasants Forever
15.4% Pollinator Partnership
7.7% Right-of-way as Habitat Working Group
6.2% Right-of-way Stewardship Council
81.5% Utility Arborist Association
1.5% Wildlife Habitat Council
6.2% Wild Turkey Federation
13.8% Other: (9 responses: no central theme)

20. How important are the following International Society of Arboriculture (ISA) credentials to your program? n=64 to 70

Credential (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
ISA Certified Tree Worker Climber Specialist®	5.8	15.9	59.4	13.0	5.8	2.97
ISA Certified Tree Worker Aerial Lift Specialist®	5.8	15.9	58.0	13.0	7.2	3.00
ISA Certified Arborist®	4.3	2.9	11.4	24.3	57.1	4.27
ISA Certified Municipal Specialist®	15.6	31.3	45.3	4.7	3.1	2.48
ISA Certified Utility Specialist™	4.3	2.9	18.8	37.7	36.2	3.99
ISA Board Certified Master Arborist®	13.4	20.9	52.2	9.0	4.5	2.70
ISA Tree Risk Assessment Qualification	4.4	7.4	39.7	29.4	19.1	3.51

21. How well does your management understand the following UVM considerations? n=66 to 67

UVM Consideration (% of total & mean)	Very Little (1)	Little (2)	Neither Little or Much (3)	Much (4)	Very Much (5)	Mean Index Score
Benefits of tree removals	0.0	3.0	16.4	22.4	58.2	4.36
Compliance	1.5	3.0	10.6	18.2	66.7	4.45
Cost of deferring maintenance	3.0	10.4	14.9	29.9	41.8	3.97
Effect of UVM on reliability	0.0	1.5	10.4	17.9	70.1	4.57
Liability *(e.g., consequence of tree causes electrical hazard or fire risks)*	1.5	4.5	12.1	30.3	51.5	4.26
Long-term cost effectiveness of a proactive UVM program	3.0	6.0	14.9	34.3	41.8	4.06
Need for consistent funding	3.0	7.5	3.0	40.3	46.3	4.19
Need for professionalism in UVM	1.5	3.0	14.9	28.4	52.2	4.27
Problems related to underfunding UVM	4.5	13.4	9.0	29.9	43.3	3.94
Variability of natural systems	7.6	16.7	30.3	25.8	19.7	3.33
Other: (2 response: Labor scarcity, tree response to pruning)	-	-	-	-	-	-

22. Does your program conduct work audits post-work inspection? n=67 (Yes or No) n=61 (If yes)

(CHECK ONE)

94.4% Yes → If yes, % audited 81.3 (mean, 4.3 SE), 2 to 100

5.6% No

23. What was your total UVM Expenditure in 2018? n=66

27,182,769 (mean, 7.0M SE), 50K to 320M (range) $ Total Expenditures

24. Is your UVM budget adequate to meet current needs as defined in your work plan or your identified annual UVM budget needs? This includes planning, maintenance, removal, inventory, education, etc. n=70 (Yes or No)

47.1% Yes n=33 (If no)

52.9% No → If no, % below need 28.9 (mean, 4.3 SE), 5 to 100

25. Has your UVM budget been stable over the past five years? n=67

(CHECK ONE)

53.7% Yes

46.3% No

26. What were your 2018 program expenditures? n=4 to 59 (Please enter "0" if none.)

UVM Expenditure Category	Total Expenditures ($ by Category)	Unplanned Expenditures (% of Category)
Example Answer	*$12,256,265*	*22%*
Transmission	6,927,258 (2,390,504 SE)	4.02 (1.32 SE)
Sub-transmission	4,912,886 (2,218,245 SE)	2.08 (0.94 SE)
Distribution	25,428,476 (6,412,338 SE)	10.85 (2.17 SE)
Total	30,348,253 (8,008,007 SE)	10.63 (2.02 SE)

27. What budget format do you employ for planning (see definitions)? n=67

(CHECK ONE)

17.9% Entrepreneurial (Management sets based company goals)
49.3% Line-item (Itemized categories and accounts)
0.0% Performance (Based on performance measures)
23.9% Program (Items based on programs rather than accounts)
9.0% Zero-based (Annually creating a budget from scratch)

28. What contracting types do you use in your UVM program? n=70

(CHECK ALL THAT APPLY)

31.4% Hard Price
11.4% Performance-based
88.6% Time and Material
50.0% Unit
14.3% Other: (10 responses: 50% were lump sum)

29. What percent of time is allocated for the following quality assurance and quality control methods? (Please enter % of time by method used.) n=32 to 58

Utility Area	N	None	Sample	100% Drive-by	100% Field Audit	Total (%)
Example answer		*0*	*12*	*72*	*16*	*100*
Distribution secondary	45	4.56	23.22	31.89	40.33	100
Distribution primary	58	4.28	17.69	31.03	47.00	100
Subtransmission	34	0.00	21.12	20.44	58.44	100
Transmission	32	3.13	12.91	18.44	65.53	100

30. What is the average salary or hourly pay rate by UVM position?

Position Categories	In-house	Contractor
Example Answer (salary)	*$52,300*	*$59,750*
Department head (salary)	116,288	82,500
Utility arborist/manager (1 level below department head) (salary)	86,877	64,556
Utility arborist/general foremen (2 levels below the department head) (salary)	71,813	63,775
Example Answer (hourly)	*$26.32*	*$19.54*
Crew leader (hourly)	29.27	30.14
Qualified utility arborist (hourly)	26.47	24.85
Qualified utility arborist trainee (hourly)	19.61	21.58
Ground worker (hourly)	17.10	19.94
Chemical applicator (hourly)	19.57	26.69
Planner Q/A specialist (hourly)	32.94	27.53
Other: (3 responses)	31.25	33.28

31. Do you conduct work on time-based cycles? n=71

(CHECK ONE)

88.7% Yes

11.3% No → (PLEASE GO TO QUESTION 33)

32. What best describes your work approach for time-based cycles? n=65

(CHECK ONE)

3.1% Reactive

3.1% Just in time

3.1% Reliability based

81.5% Regular work cycle

If regular cycle, current cycle length (years) 4.5 (0.18 SE)

If regular cycle, desired cycle length (years) 3.8 (0.19 SE)

9.2% Variable work cycle: (not specified)

33. Do you work single and three-phase lines on different cycles? n=64

(CHECK ONE)

9.4% Yes

90.6% No

34. Do you work in a circuit or a grid (polygon) basis? n=66

(CHECK ONE)

78.8% Grid

21.2% Circuit

35. What were your 2018 program expenditures per UVM area? n=31 to 53

(Please enter "0" if none.)

30,819,334 (8,525,039 SE)	Total UVM expenditures
26,591,007 (7,129,611 SE)	Total UVM distribution expenditures
40.37 (4.09 SE)	Total UVM cost per customer
3,085 (482.3 SE)	Total UVM expenditures per mile
1,719,989 (419,293 SE)	Total UVM expenditures for unplanned work

SECTION IV – PRUNING

1. What was the tree condition at the time of maintenance? n=50 to 54

(Please enter "0" if none.)

21.3 (3.5 SE) Percent of trees in contact with line (n=50)
24.6 (3.7 SE) Percent of trees over-hanging line (n=54)

2. Do you have a chemical pruning program? n=67

(CHECK ONE)

13.4% Yes
86.6% No

3. Do you clear "ground to sky" on the wire side of trees? n=65

(CHECK ONE)

58.5% Yes
41.5% No → (PLEASE GO TO QUESTION 5)

4. Where do you clear "ground to sky" on the wire side of trees? n=39

(CHECK ALL THAT APPLY)

25.6% Rural locations
48.7% Three-phase lines
10.3% To the first protective device
38.5% All locations
30.8% Other: (12 responses, depends on situation)

5. Rate the importance of the following pruning considerations in determining the clearances distances. n=63 to 64

Pruning Considerations (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Expected weather in the vicinity	9.5	15.9	28.6	33.3	12.7	3.24
Facility construction (e.g., single pole, crossarms, bundled, secondary)	7.9	4.8	22.2	33.3	31.7	3.76
Facility priority (e.g., voltage, overcurrent protection, customers served, high-value customers)	6.3	3.1	7.8	40.6	42.2	4.09
Line location (e.g., urban, suburban, rural, remote)	6.3	6.3	35.9	31.3	20.3	3.53
Maintaining tree structure	8.1	8.1	37.8	35.1	10.8	3.32
Number of customers served	11.1	1.6	19.0	54.0	14.3	3.59
Planned cycle length	3.1	3.1	15.6	39.1	39.1	4.08
Reliability	3.1	0.0	9.4	21.9	65.6	4.47
Risk reduction (safety)	0.0	1.6	9.4	31.3	57.8	4.45
Site factors (e.g., # and type of trees, terrain, cultural resources)	6.3	4.7	17.2	48.4	23.4	3.78
Tree positions relative to the line	4.8	3.2	4.8	50.8	36.5	4.11
Three or single-phase lines	7.9	0.0	11.1	42.9	38.1	4.03

6. Please specify your distribution primary clearances. (Check the NM box if no maintenance, check the CO box if clear only to relieve abrasion or deflection, or enter the applicable distance for side, under, and overhang clearances.) n=57 to 62

Units are in: ft (feet) (CHECK ONE)

☐ ft (feet)

☐ m (meters)

	---------number---------		---------- Distance (ft) ----------		
Line Type	**NM[1]**	**CO[2]**	**Side**	**Under**	**Overhang**
Single-phase (n=61)	2(3%)	2(3%)	10.60	10.31	13.57
Three-phase (n=61)	1(2%)	2(3%)	10.93	10.65	13.88
Open wire (n=57)	5(9%)	10(18%)	6.78	6.32	6.08
Triplex (n=62)	7(11%)	32(52%)	3.99	3.80	4.92

[1] NM = No maintenance

[2] CO = Clear only to relieve abrasion or deflection

7. Rate the following factors for their importance regarding how much overhang clearance you specify on distribution primary lines. n=54 to 64

Pruning Factors (% of total & mean)	**Very Unimportant (1)**	**Unimportant (2)**	**Neither Important or Unimportant (3)**	**Important (4)**	**Very Important (5)**	**Mean Index Score**
Branch defect	7.8	0.0	1.6	18.8	71.9	4.47
Branch size	7.8	3.1	15.6	50.0	23.4	3.78
Community expectations	17.7	3.2	25.8	40.3	12.9	3.27
Expected weather in the vicinity	15.6	9.4	26.6	31.3	17.2	3.25
Line priority	14.3	0.0	7.9	39.7	38.1	3.87
Mass damping	18.5	9.3	48.1	13.0	11.1	2.89
Storm exposure	14.3	0.0	22.2	36.5	27.0	3.62
Tree biomechanics	8.1	0.0	12.9	48.4	30.6	3.94
Tree species	4.8	0.0	3.2	31.7	60.3	4.43

8. Rate the importance of the following pruning objectives to your UVM program. n=64 to 66

Pruning Objectives (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Clearance	1.5	1.5	0.0	22.7	74.2	4.67
Maintaining tree structure	1.5	4.6	23.1	47.7	23.1	3.86
Reliability	1.5	0.0	0.0	7.6	90.9	4.86
Risk reduction (safety)	0.0	0.0	1.6	23.4	75.0	4.73

9. How important are the following standards, best practices and resources to your UVM pruning specifications? n=71

Standards (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
ANSI A300 - Part 1	1.4	1.4	9.9	18.3	69.0	4.52
ISA Utility Pruning of Trees Best Management Practices	2.8	1.4	4.2	32.4	59.2	4.44
Pruning of Trees Near Electric Utility Lines: A Field Pocket Guide for Qualified Line-Clearance Tree Workers	2.8	9.9	14.1	31.0	42.3	4.00
Other: (11 responses)	0.0	0.0	0.0	27.3	72.7	4.71

10. How important are the following locations to your pruning program? n=64 to 66

Pruning Locations (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Remote	4.6	1.5	27.7	40.0	26.2	3.82
Rural	4.6	1.5	30.8	38.5	24.6	3.77
Urban-rural interface	3.1	1.5	23.1	36.9	35.4	4.00
Suburban	3.0	1.5	24.2	28.8	42.4	4.06
Urban	3.1	3.1	23.4	28.1	42.2	4.03

SECTION V – INTEGRATED VEGETATION MANAGEMENT

1. What information do you collect for your IVM program? n=63

(CHECK ALL THAT APPLY)

71.4% Address
23.8% Branch distance from the line
34.9% GPS coordinates
15.9% Growth rate
50.8% Pole number
60.3% Species
34.9% Tree condition
33.3% Tree density
42.9% Tree diameter
30.2% Tree height
17.5% Tree orientation
19.0% Tree risk assessment rating
9.5% Other (6 responses)
- Number of trees/mile
- Keep track of circuits cut
- Miles of circuit/Area to be trimmed
- Monitor status
- Number pruned, Number removed
- Voltage, work prescription, line name, permit date, crew code, crew hours, crew work date, herbicide, lift or manual

2. Which treatment methods do you use for Tree Growth Regulators (TGRs)? n=21

(CHECK ALL THAT APPLY)

38.1% Soil drench
57.1% Soil injection
9.5% Trunk injection

3. Rank the importance of the following reasons for conducting IVM (1 = least to 5 = most important, use each # once only). n=56

3.04 (0.18 SE) Compliance
2.95 (0.16 SE) Cost-effectiveness
2.34 (0.21 SE) Environmental stewardship
3.34 (0.20 SE) Safety
3.34 (0.17 SE) Service reliability

4. How well are the following standards and best practices incorporated into your program? n=68 to 69

Pruning Standards (% of total & mean)	Very Little (1)	Little (2)	Neither Little or Much (3)	Much (4)	Very Much (5)	Mean Index Score
ANSI A300 Part 7 - Integrated Vegetation Management	5.8	2.9	14.5	27.5	49.3	4.12
ANSI A300 Part 9 - Tree Risk Assessment	7.2	11.6	31.9	33.3	15.9	3.39
ISA BMPs - Integrated Vegetation Management	4.3	2.9	15.9	43.5	33.3	3.99
ISA BMPs - Tree Risk Assessment Qualification	10.1	14.5	46.4	18.8	10.1	3.04
Utility Arborist Association Best Management Practices - Closed Chain of Custody	16.2	11.8	44.1	11.8	16.2	3.00
UAA Tree Risk Assessment and Abatement for Fire-Prone States and Provinces	37.7	8.7	42.0	5.8	5.8	2.33

5. How important are the following considerations in setting IVM objectives? n=60 to 64

IVM Objective Considerations (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Access	3.2	3.2	21.0	48.4	24.2	3.87
Compliance	1.6	1.6	13.1	37.7	45.9	4.25
Cost efficiency	0.0	0.0	6.5	41.9	51.6	4.45
Cultural site protection	0.0	5.0	48.3	31.7	15.0	3.57
Environmental stewardship	0.0	3.2	35.5	43.5	17.7	3.76
Facility protection	0.0	0.0	4.9	41.0	54.1	4.49
Safety	0.0	0.0	3.1	20.3	76.6	4.73
Security	0.0	1.6	38.7	27.4	32.3	3.90
Service reliability	0.0	0.0	3.1	9.4	87.5	4.84
Workload evaluations	0.0	4.9	36.1	49.2	9.8	3.64

6. How important are the following methods in conducting workload evaluations? n=60 to 62 (3 for other)

Assessment Methods (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Aerial photos	3.2	3.2	21.0	48.4	24.2	2.93
Ground evaluations	1.6	1.6	13.1	37.7	45.9	4.69
LiDAR	0.0	0.0	6.5	41.9	51.6	2.62
Satellite imagery	0.0	5.0	48.3	31.7	15.0	2.69
Unmanned aerial systems (UAS)	0.0	3.2	35.5	43.5	17.7	2.37
Other: (3 responses: Aerial/Helicopter)	0.0	0.0	0.0	0.0	100	5.00

7. Does your program have a dedicated tree risk assessment program based in the ISA tree risk assessment best management practices (Smiley, Matheny, and Lilly, 2011)? n=68

(CHECK ONE)

20.6% Yes
79.4% No

8. Are site evaluations part of your program? n=69

(CHECK ONE)

85.5% Yes
14.5% No → (PLEASE GO TO QUESTION 10)

9. Which site evaluations are part of your program? n=56

(CHECK ALL THAT APPLY)

76.8% Access routes
62.5% Anticipated control methods
30.4% Archeological and cultural issues
25.0% Fire risk
48.2% Funding availability
66.1% Labor and equipment resource availability
67.9% Land ownership and use
67.9% Line construction
73.2% Line location
76.8% Line voltage and criticality
55.4% Presence of species concern
78.6% Right-of-way width
85.7% Safety
23.2% Soil types
51.8% Topography
46.4% Vulnerable or protected areas
46.4% Water resources
64.3% Wire height off the ground
50.0% Workload
5.4% Other (3 responses)
Biomes, climate, plant hardiness, clearance to conductor
Insect damage
Predominant mature edge species can dictate which herbicide mix is used

10. Do action thresholds apply to your decision making? n=69

(CHECK ONE)

76.8% Yes
23.2% No → (PLEASE GO TO QUESTION 12)

11. What are your action thresholds? n=53

(CHECK ALL THAT APPLY)

86.8% Minimum clearances
69.8% Time length
52.8% Tree risk rating
37.7% Vegetation density
49.1% Vegetation height
15.1% Other (8 responses: Species, Tree Health, Binary tree risk)

12. What criteria do you use to develop your tolerance levels? n=61

(CHECK ALL THAT APPLY)

44.3% Compliance with state/provincial or federal regulations
34.4% Density of vegetation
67.2% Minimum vegetation clearance distance (MVCD) FAC-003-4
13.1% Percent tree contact for distribution → Below Specify %
19.7% Other (12 various responses) 28.0 (Mean, 18.2 SE), 5 to 100% range

13. How important are the following control methods to your IVM program? n=67 to 69

IVM Methods (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Biological	10.1	14.5	47.8	17.4	10.1	3.03
Chemical	2.9	2.9	7.1	30.0	57.1	4.36
Cultural	6.0	6.0	52.2	23.9	11.9	3.30
Engineering	4.5	10.4	35.8	34.3	14.9	3.45
Physical (manual and mechanical)	0.0	0.0	0.0	24.6	75.4	4.75

14. Do you use closed chain of custody in your program? n=60

(CHECK ONE)

45.0% Yes
55.0% No

15. Rate the importance of the following treatment options to your program (1 = lowest to 5 = highest). n=59 to 63

IVM Treatment Options (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Aerial	42.4	27.1	16.9	8.5	5.1	2.07
Bare ground treatment	11.7	15.0	20.0	21.7	31.7	3.47
Basal	8.2	8.2	19.7	39.3	24.6	3.64
Chemical tree-pruning	49.2	14.8	29.5	4.9	1.6	1.95
Cut stubble	22.6	11.3	21.0	21.0	24.2	3.13
High volume foliar	16.1	9.7	21.0	24.2	29.0	3.40
Stump treatment	6.3	0.0	4.8	23.8	65.1	4.41
Trunk injection	39.0	18.6	32.2	6.8	3.4	2.17
Other: (17 responses: 16 were low volume foliar ~)	0.0	0.0	5.9	11.8	82.4	4.76

16. Does your program employ mechanical pruning (e.g., machines or helicopters) for line clearance? n=70, n=36 if yes response

(CHECK ONE)

64.3% Yes → If yes, 17.8 (2.8 SE) % of total UVM budget

35.7% No

17. Do you use tree growth regulators (TGRs)? n=70

(CHECK ONE)

25.7% Yes

74.3% No → (PLEASE GO TO QUESTION 19)

18. How important are TGRs to your program? n=20

10% Very unimportant

30% Somewhat unimportant

5% Neither unimportant or important

55% Somewhat important

0% Very important

3.05 (Mean, 0.26 SE)

19. How important are the following cultural control methods to your program? n=66 to 68

Cultural Control Methods (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Cover type conversion	14.7	13.2	29.4	27.9	14.7	3.15
Hydroseeding	38.2	22.1	36.8	2.9	0.0	2.04
Fertilizing	47.1	17.6	35.3	0.0	0.0	1.88
Growing agricultural crops	36.8	11.8	30.9	16.2	4.4	2.40
Landscaping	19.4	11.9	34.3	28.4	6.0	2.90
Planting or seed compatible plants	14.9	11.9	35.8	25.4	11.9	3.07
Prairie restoration	31.8	18.2	33.3	13.6	3.0	2.38
Wire-border zone	11.9	10.4	29.9	22.4	25.4	3.39
Other: (no responses)	-	-	-	-	-	-

20. How important are the following engineering solutions to your UVM program? n=59 to 62

Engineering solutions (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Alley arms	14.8	11.5	39.3	29.5	4.9	2.98
Covered overhead construction	29.5	13.1	39.3	14.8	3.3	2.49
Hendrix spacers	22.0	23.7	37.3	13.6	3.4	2.53
Moving poles for the lines to avoid trees	11.3	14.5	29.0	32.3	12.9	3.21
Rising poles	13.1	16.4	31.1	34.4	4.9	3.02
Underground construction	11.3	3.2	40.3	37.1	8.1	3.27
Prairie restoration	31.1	13.1	47.5	6.6	1.6	2.34
Wire-border zone	16.1	12.9	33.9	22.6	14.5	3.06
Other: (no responses)	-	-	-	-	-	-

SECTION VI – ELECTRICAL OPERATIONS

1. What percent of total transmission outages and sub-transmission outages are vegetation related on your system? n=61

System	% of Total Outages (Std Error)	% of Total Customer Minutes (Std Error)
Example Answer	*61*	*16*
Distribution outages caused by vegetation	23.19 (2.63 SE)	21.65 (3.12 SE)
Sub-transmission outages caused by vegetation	2.04 (SE 0.85)	3.84 (1.72 SE)
Transmission outages caused by vegetation	1.13 (0.47 SE)	1.21 (0.74 SE)

2. Is reliability part of your UVM strategy? n=71

(CHECK ONE)

95.8% Yes

4.2% No → (PLEASE GO TO QUESTION 4)

3. How important are the following reliability metrics to your program? n=54 to 59

Reliability Metrics (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
ASAI	25.9	13.0	31.5	18.5	11.1	2.76
CAIDI	5.2	3.4	6.9	34.5	50.0	4.21
MAIFI	13.0	24.1	37.0	16.7	9.3	2.85
SAIDI	5.1	3.4	0.0	32.2	59.3	4.37
SAIFI	3.4	1.7	3.4	37.9	53.4	4.36

ASAI: Average System Availability Index
CAIDI: Customer Average Interruption Duration Index
MAIFI: Momentary Average Interruption Frequency Index
SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index

4. Is distribution fuse coordination aligned with UVM on your system? n=63

(CHECK ONE)

47.6% Yes

52.4% No

5. Please rate the importance of the following protective strategies. n=63 to 64

Protective Strategies (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Expanded clearances at the time of work	1.6	6.3	14.3	50.8	27.0	3.95
Greater actions thresholds on three-phase lines	4.8	3.2	19.0	46.0	27.0	3.87
Greater tolerance levels on three-phase lines	12.5	6.3	39.1	26.6	15.6	3.27
Shorter cycles on three-phase lines	6.3	14.1	43.8	25.0	10.9	3.20
Other: (0 responses)	-	-	-	-	-	-

6. Does your program have different strategies on three- and single-phase lines? n=67

(CHECK ONE)

35.8% Yes

64.2% No → (PLEASE GO TO QUESTION 8)

7. How important are the following strategies on three-phase compared to single-phase lines? n=22 to 23

Strategies (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Broader tolerance thresholds	31.8	0.0	22.7	31.8	13.6	2.95
Greater action thresholds	8.7	0.0	13.0	26.1	52.2	4.13
Greater clearances at time of work	4.2	0.0	20.8	33.3	41.7	4.08
Shorter cycles	16.7	0.0	58.3	12.5	12.5	3.04
Other: (1 response, more tree removal)	-	-	-	-	-	-

8. What percent of vegetation-related outages are caused by the following outage types? n=53

Outage type	% of outages
Example Answer	*35*
Broken branches	19.4 (2.6 SE)
Grow-ins	11.4 (2.4 SE)
Off right-of-way trees	34.4 (4.1 SE)
Overhang	6.0 (1.4 SE)
Whole tree failure	27.2 (3.7 SE)
Other: (7 responses, beaver, public damage, vines)	1.6 (1.1 SE)
Total	= 100%

SECTION VII – STORM RESPONSE

1. Do you leave storm debris on site? n=67

(CHECK ONE)

70.1% Always
25.4% Never
4.5% Occasionally → (If so, 74.6% (7.3 SE) percentage of time)

2. How important are the following factors to storm response? n=65 to 69

Storm Response Factors (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Animals and insects	19.7	15.2	40.9	19.7	4.5	2.74
Communication other than cell phones	1.5	10.4	19.4	35.8	32.8	3.88
Contracts with UVM companies to respond to difficult weather conditions	1.5	2.9	11.8	36.8	47.1	4.25
Driving	1.5	1.5	5.9	51.5	39.7	4.26
Electrical hazard communication protocol	1.5	0.0	4.5	28.4	65.7	4.57
Equipment availability, repair and maintenance	1.5	0.0	8.8	41.2	48.5	4.35
Equipment rental	10.4	16.4	52.2	16.4	4.5	2.88
Extended hours	0.0	0.0	8.8	47.1	44.1	4.35
Fatigue	0.0	0.0	0.0	44.9	55.1	4.55
Food	0.0	0.0	4.3	55.1	40.6	4.36
Fuel	1.5	1.5	5.9	48.5	42.6	4.29
Housing	3.0	3.0	11.9	46.3	35.8	4.09
Incident command	3.0	0.0	9.0	38.8	49.3	4.31
Mutual assistance agreements	1.5	3.0	17.9	28.4	49.3	4.21
Rerouting and navigations	1.5	1.5	38.5	40.0	18.5	3.72
Rosters	0.0	0.0	15.4	52.3	32.3	4.17
Supervision	0.0	0.0	2.9	38.2	58.8	4.56
Safety	0.0	0.0	0.0	4.3	95.7	4.96
Wood under tension	0.0	0.0	2.9	48.5	48.5	4.46

3. Does your company have storm emergency declaration protocols? n=70

(CHECK ONE)

92.9% Yes

7.1% No → (PLEASE GO TO QUESTION 5)

4. Does a declaration affect how UVM storm responders are paid (e.g., does it trigger overtime)? n=61

(CHECK ONE)

52.5% Yes

47.5% No

5. What criteria do you use in declaring a storm emergency? n=64

(CHECK ALL THAT APPLY)

18.8% Amount of precipitation
43.8% Duration of storm
81.3% Extent of infrastructure damage
28.1% Geographic area covered by storm
92.2% Number of customers out of power
42.2% Number of interruptions
56.3% Percent of customers out of power
39.1% Percent of area out of power
28.1% Type of precipitation (e.g., freezing rain, snow)
34.4% Type of storm
34.4% Wind speed

6. How important are the following storm preparation factors in your vegetation management storm response? n=65 to 68

Protective Strategies (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Incident Command System (ICS)	2.9	2.9	19.1	25.0	50.0	4.16
Emergency operations center	0.0	1.5	16.2	32.4	50.0	4.31
Pre-storm communication checks	0.0	1.5	16.7	45.5	36.4	4.17
Storm practice drills	4.5	4.5	28.4	46.3	16.4	3.66
Pre-mobilization	1.5	1.5	30.8	41.5	24.6	3.86
Coordination with local government	1.5	7.6	30.3	37.9	22.7	3.73
Other: (1 response: Prep cranes, storm alerts)	-	-	-	-	-	-

7. Who declares a storm emergency? n=65

(CHECK ALL THAT APPLY)

38.5% Operations director
40.0% Operations manager
20.0% President
20.0% Vice-president
26.2% Storm response committee
15.4% Other (9 responses)
City manager (2); Distribution system operator; Duty supervisor; General manager; Grid control center; Incident commander (2); Shift supervisor

8. Do you cap hours worked during storms? n=66

(CHECK ONE)

63.6% Yes
36.4% No → (PLEASE GO TO QUESTION 10)

9. What strategy do you use to cap hours during for the following time periods? n=5 to 26

Time Period	Total # of Hours	Consecutive # of Hours
Example Answer	*16*	*8*
First 24 hours	18.5 (0.73 SE)	15.9 (1.42 SE)
Daily	15.9 (0.21 SE)	13.2 (0.86 SE)
Weekly	14.9 (0.73 SE)	10.7 (1.33 SE)
Monthly	15.4 (0.57 SE)	10.4 (1.60 SE)
Other: (4 responses: 16 in 24 no more continuous clock; After 24 hrs 16 hours on, 8 hours off; Must rest 8 hrs after working 16 consecutive hours; Storm duration).		

10. How is your media department involved in storm response? n=62

(CHECK ALL THAT APPLY)

71.0% Communicating estimated time of restoration
59.7% Media relations control 100% of the messaging for storms
30.6% Pre-approved message for tree crews (e.g., “We are working hard to get things back to normal.”)
77.4% Press releases on the extent of outages
37.1% Restrictions on front line employee communications
6.5% Other (4 responses):
Public Information Officer (1)
Social Media (3)

11. Do you document production data during storms? n=67

(CHECK ONE)

50.7% Yes
49.3% No → (PLEASE GO TO QUESTION 13)

12. What production data do you collect during storms? n=35

(CHECK ALL THAT APPLY)

- 11.4% Ft^2 / m^2 worked
- 94.3% Hours worked
- 71.4% Locations worked
- 8.6% Loads or ft^3 / m^3 collected
- 25.7% Numbers of trees worked

13. How important is a pre-approved message for tree crews to provide to media (e.g., "We are working hard to get things back to normal.)"? n=65

- 18.5% Very unimportant
- 15.4% Somewhat unimportant
- 36.9% Neither unimportant or important
- 20.0% Somewhat important
- 9.2% Very important
- 2.86 (Mean, 0.15 SE)

SECTION VIII – COMMUNICATIONS

1. How do you communicate with customers before work? n=70

(CHECK ALL THAT APPLY)

- 55.7% Contract utility foresters/arborists
- 57.1% In-house utility foresters/arborists
- 12.9% UVM managers
- 50.0% Tree crews
- 35.7% Other
  - Direct mail (10 responses, 14.3%)
  - Phone message (10 responses, 14.3%)
  - Door hanger (6 responses, 8.6%)

2. Do you conduct customer satisfaction surveys? n=70

(CHECK ONE)

- 54.3% Yes
- 45.7% No

3. How do you conduct customer satisfaction surveys? n=37

(CHECK ALL THAT APPLY)

- 27.0% Door hanger
- 8.1% Follow-up personal visit
- 43.2% Phone call
- 40.5% Website directed survey
- 16.2% Other
  - Survey (2 responses, 5.4%)
  - Focus group (1 responses, 2.7%)
  - Mail/web (1 responses, 2.7%)
  - Outside firm (1 responses, 2.7%)
  - Select group (1 responses, 2.7%)

4. Rate the importance of the following groups for UVM-related communications of utility operations (outside of UVM). n=66 to 67

Groups (% of total & mean)	Very Unimportant (1)	Unimportant (2)	Neither Important or Unimportant (3)	Important (4)	Very Important (5)	Mean Index Score
Commercial customers	0.0	9.0	22.4	29.9	38.8	3.99
County government	1.5	4.5	28.8	39.4	25.8	3.83
Environmental organizations	3.0	10.6	42.4	30.3	13.6	3.41
Federal land management agencies	4.5	10.6	27.3	30.3	27.3	3.65
Media	4.5	1.5	30.3	39.4	24.2	3.77
Municipal government	1.5	3.0	15.2	45.5	34.8	4.09
Neighborhood associations	1.5	9.1	37.9	40.9	10.6	3.50
Non-utility arborists (municipal, commercial and researchers)	3.0	9.1	50.0	24.2	13.6	3.36
Owners and investors	4.8	7.9	34.9	31.7	20.6	3.56
Property owners	1.5	1.5	4.5	38.8	53.7	4.42
Regulatory agencies	3.0	6.1	19.7	31.8	39.4	3.98
State department of natural resources	3.0	4.5	34.8	40.9	16.7	3.64
Residential customers	0.0	3.0	4.5	34.3	58.2	4.48
Suppliers	6.2	9.2	44.6	30.8	9.2	3.28
UVM contractors	0.0	0.0	12.1	34.8	53.0	4.41
Other: 1 response (internal specific operational groups)	0.0	0.0	0.0	0.0	100.0	5.00

5. Rate the importance of the following types of communication you use for UVM (1 = least to 5 = most important). n=63 to 68

3.57 (0.18 SE) Brochures
2.51 (0.17 SE) E-mail messages (blasts)
2.86 (0.16 SE) Press releases
3.45 (0.17 SE) Social media
2.30 (0.18 SE) Town hall meetings

RESPONDING UTILITIES

- Alabama Power
- American Electric Power – Ohio
- Ameren Illinois
- Appalachian Electric Cooperative
- Appalachian Power
- ATCO Electric
- Avista Utilities
- Black Hills Energy
- Blue Grass Energy
- Boone Electric Cooperative Central Hudson Gas and Electric
- Central Hudson Gas and Electric
- Chelan County PUD Consumer's Energy
- City of Naperville Electric Utility
- City of Tallahassee
- City of Westerville Electric
- City Utilities of Springfield
- Cleveland Utilities
- Consolidated Electric Cooperative
- Consumer's Energy
- Cuivre River Electric Cooperative
- Dairy Power
- Dayton Power and Light
- Duquesne Light Company
- Duke Energy Corporation
- East Central Energy
- Edmond Electric
- Electric Power Board
- Entergy Corporation
- Evergy
- First Energy
- Fortis Alberta
- Golden Valley Electric Association
- Huntsville Utilities
- Hutchinson Utilities
- Hydro One Networks
- Independence Power and Light
- JEA
- Kirkwood Electric
- Lansing Power Board
- Liberty Utilities New Hampshire
- Madison Gas and Electric
- Manitoba Hydro
- Menasha Utilities
- MidAmerican Energy Co
- Milan Public Utilities National Grid
- National Grid
- New Brunswick Power
- Oklahoma Electric Cooperative
- Orange Rockland
- Pierce Pepin Cooperative Service
- Pioneer Electric Cooperative
- Provo City Power
- Public Service of New Mexico
- Public Service of Oklahoma
- Puget Sound Energy
- Rappahannock Electric Cooperative
- Richland Electric Cooperative
- Sacramento Utility District
- Salt River Project
- SaskPower
- Sevier County Electric System
- Tacoma Power
- Tipmont REMC
- Tullahoma Utilities Authority
- Union Power Cooperative
- Velco
- Waverly Utilities
- Xcel Energy: Public Service of Colorado
- Xcel Energy: Northern States Power -Minnesota
- Xcel Energy: Northern States Power -Wisconsin
- Xcel Energy: Southwestern Public Service



ANY QUESTIONS? PLEASE CONTACT

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S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U- 21870

EXHIBITS

OF

CAITLIN M. TETRICK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources
Electric Low Voltage Distribution (LVD) Workplan

Case No.: U-21870
Exhibit No.: A-178 (CMT-1)
Page: 1 of 1
Witness: CMTetrick
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	2023 YE Actual	2024 YE Actual	2025 YE Projected 12 Mos Ending 12/31/2025	2026 YE Projected 12 Mos Ending 12/31/2026	2027 YE Projected 12 Mos Ending 12/31/2027	Bridge Period 16 Mos Ending 4/30/2026	Test Period 12 Mos Ending 4/30/2027
1	LVD Electric Operations Resource Requirement (FTEs)	1,104	1,155	1,229	1,537	1,742	1,537	1,742
2	LVD Consumers Energy Resources (FTEs)	981	1,017	1,091	1,306	1,481	1,306	1,481
3	LVD Consumers Energy Resources (percent change from prior year FTE)	15%	4%	7%	20%	13%	28%	36%
4	LVD Contractor Resources (FTEs)	123	138	138	231	261	231	261
5	LVD Contractor Resources (percent change from prior year FTE)	-	12%	0%	67%	13%	67%	13%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources
Electric High Voltage Distribution (HVD) Workplan

Case No.: U-21870
Exhibit No.: A-179 (CMT-2)
Page: 1 of 1
Witness: CMTetrick
Date: June 2025

Line No.	(a) Description	(b) 2023 YE Actual	(c) 2024 YE Actual	(d) 2025 YE Projected 12 Mos Ending 12/31/2025	(e) 2026 YE Projected 12 Mos Ending 12/31/2026	(f) 2027 YE Projected 12 Mos Ending 12/31/2027	(g) Bridge Period 16 Mos Ending 4/30/2026	(h) Test Period 12 Mos Ending 4/30/2027
1	HVD Electric Operations Resource Requirement (FTEs)	377	409	504	539	530	539	530
2	HVD Consumers Energy Resources (FTEs)	191	209	233	261	270	261	270
3	HVD Consumers Energy Resources (percent change from prior year FTE)	-2%	2%	11%	12%	3%	25%	29%
4	HVD Contractor Resources (FTEs)	186	200	271	278	260	278	260
5	HVD Contractor Resources (percent change from prior year FTE)	4%	8%	36%	3%	-6%	39%	-6%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

EXHIBITS

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the Property Tax Rate for the Test Year

Case No.: U-21870
Exhibit No.: A-180 (BJV-1)
Page: 1 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Amount (millions)	(c) Amount (millions)	(d) Amount (millions)	(e) Source
1	Electric Property Taxes Paid - 2026 Estimate			$ 281.9	WP BJV-5, L-5
2	Electric Property Taxes on 2026 Plant Investment			33.6	Ex. A-180 (BJV-1), p.2, L-9
3	2027 Fossil Plant Valuation Tax Reduction			(0.1)	WP BJV-5, L-5
4	Electric Property Taxes on Real Property Taxable Value Increases			1.2	Ex. A-180 (BJV-1), p.3, L-4
5	Electric Property Taxes to be Paid - 2027			$ 316.6	
6	2026 Fiscal Year Property Taxes expensed in 2027			141.0	(Line 1 * 50.0%) [1]
7	2027 Property Taxes expensed in 2028			(158.3)	(Line 5 * 50.0%) [1]
8	Electric Property Tax Expense - 2027			$ 299.3	
9	Prorated Electric Property Tax Expense (May - December 2026)			183.7	WP BJV-5, L-10
10	Prorated Electric Property Tax Expense (January - April 2027)			96.8 [4]	
11	Prorated Electric Property Tax Expense			280.5	(L-10 + L-11)
12	2026 Estimated Year-End Plant-in-Service		$ 20,714.6 [2]		
13	2026 Estimated Construction Work-in-Progress	$ 595.2 [3]			
14	@ 50%	50.00%			
15	2026 Estimated Construction Work-in-Progress		$ 297.6		
16	Estimated Taxable Plant			$21,012.2	(L-13 + L-16)
17	Property Tax Rate			0.013349387	(L-12 / L-17)

Footnotes
[1] The 50.0% factor is from the 2024 CE Property Tax Fiscal Year Study
[2] Plant in Service Balance as of 12-31-2026; Plant Model U-21870; PIS (WP-PDD-21); Cell AH29 + JHC1&2 (WP-PDD-9), Cell AM18 + JHC3 (WP-PDD-9), Cell AM30
[3] Construction Work in Progress Balance as of 12-31-2026; Plant Model U-21870; CWIP (WP-PDD-24); Cell AI30
[4] Development of Estimated 2027 Prorated Property Tax Expense

2027 Estimated PT Expense	$ 299.3	Ex. A-180 (BJV-1), p. 1, L-9
Jan-Apr Expense Ratio	32.33%	Plant Model U-21870.xlsx; Input, Cells B215-E215
Prorated 2027 PT Expense	$ 96.8	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2027 Property Taxes
on 2026 Plant Investment

Case No.: U-21870
Exhibit No.: A-180 (BJV-1)
Page: 2 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**Assessed Value of Personal Property (millions)**			
2	Year-end 2026 Estimated Taxable Closings less Retirements	$ 1,404.3	[1]	
3	First Year STC Multiplier	96.0%	[2]	
4	**True Cash Value of Personal Property (millions)**	$ 1,348.1		
5	Statutory Factor for Assessed Value	50%	[3]	
6	New Plant - Assessed Value	$ 674.1		
7	**Estimated Property Tax (millions)**			
8	Estimated Composite Millage Rate	49.7863	[4]	
9	Estimated 2027 Property Taxes Paid	$ 33.6		

Footnotes
[1] 2027 Electric Rate Case Property Tax Model
[2] Michigan Dept of Treasury Form 3589 - 1st year multiplier for Electric Distribution and Equipment
[3] Article IX, Section 3 of Constitution of Michigan of 1963
[4] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2027 Estimated Electric Portion of
Real Property Taxable Value Increase

Case No.: U-21870
Exhibit No.: A-180 (BJV-1)
Page: 3 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**2027 Estimated Electric Portion of Real Property Tax Increase (millions)**			
2	2027 Real Property Taxable Value - Estimated Electric Portion	$ 23.1	[1]	
3	2027 Estimated Composite Millage Rate	49.7863	[2]	
4	2027 Estimated Electric Portion of Real Property Taxable Value increase	$ 1.2		

Footnotes
[1] 2027 Electric Rate Case Property Tax Model
[2] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Amortization of Excess Deferred Federal
Income Taxes for the Test Year

Case No.: U-21870
Exhibit No.: A-181 (BJV-2)
Page: 1 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Projected Regulatory [1] Liability Amortization	(c) Projected Annual [2] Excess Deferred Tax	(d) Proration to Test Year
1	Protected Plant Balance - Subject to ARAM			
2	2026	(37,134,000)	(27,690,000)	(18,460,000)
3	2027	(39,904,000)	(29,756,000)	(9,919,000)
4				
5	**TCJA Amortization - ARAM**			(28,379,000)
6				
7				
8				
9	Non-Protected Plant Balance - 27 years			
10	2026	3,145,000	2,345,000	1,563,000
11	2027	3,145,000	2,345,000	782,000
12				
13				
14	Non-Protected Other Balance - 10 years			
15	2026	(8,708,000)	(6,493,000)	(4,329,000)
16	2027	(8,708,000)	(6,493,000)	(2,164,000)
17				
18	**TCJA Amortization - Non ARAM**			(4,148,000)
19				
20				
21				
22	**TCJA Regulatory Liability**	(10,603,566)	(7,907,000)	(7,907,000)
23				
24				
25	**Total Test Year Excess Deferred Taxes**			(40,434,000)

[1] Based on the Company's regulatory liability amortization schedule approved in Case No. U-20309.

[2] Adjustment to pre-tax based on 1.341056 gross-up factor used in Case No. U-20309.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-181 (BJV-2)
Page: 2 of 3
Witness: BJVanBlarcum
Date: June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Projected Tax Reform Regulatory Liability & Amortization
($000)

Case No.: U-20309
Exhibit No.: A-5 (SBM-3)
Page: 1 of 1
Witness: SBMcIntosh
Date: April 2019

Line No.	(a) Description	(b) Plant Diff *	(c) Oth Plant Diff ***	(d) All Other	(e) Total Electric
1	Amortization Period	ARAM	27	10	
2					
3	**Tax Reform Regulatory Asset (Liability) After Gross Up**	**$ (1,172,029)**	**$ 89,091**	**$ (87,076)**	**$ (1,170,013)**
4					
5	**Amortization Schedule**				
6	**2019	(8,953)	1,048	(2,903)	(10,807)
7	**2020	(28,209)	3,145	(8,708)	(33,771)
8	2021	(30,187)	3,145	(8,708)	(35,749)
9	2022	(31,436)	3,145	(8,708)	(36,998)
10	2023	(35,546)	3,145	(8,708)	(41,108)
11	2024	(36,898)	3,145	(8,708)	(42,460)
12	2025	(37,086)	3,145	(8,708)	(42,648)
13	2026	(37,134)	3,145	(8,708)	(42,697)
14	2027	(39,904)	3,145	(8,708)	(45,467)
15	2028	(42,747)	3,145	(8,708)	(48,309)
16	2029	(44,426)	3,145	(5,805)	(47,085)
17	2030	(45,859)	3,145	-	(42,713)
18	2031	(46,326)	3,145	-	(43,181)
19	2032	(47,316)	3,145	-	(44,170)
20	2033	(49,093)	3,145	-	(45,948)
21	2034	(51,089)	3,145	-	(47,944)
22	2035	(44,865)	3,145	-	(41,719)
23	2036	(42,334)	3,145	-	(39,189)
24	2037	(29,201)	3,145	-	(26,055)
25	2038	(26,019)	3,145	-	(22,874)
26	2039	(25,183)	3,145	-	(22,037)
27	2040	(24,370)	3,145	-	(21,225)
28	2041	(24,256)	3,145	-	(21,110)
29	2042	(24,259)	3,145	-	(21,114)
30	2043	(24,313)	3,145	-	(21,168)
31	2044	(24,345)	3,145	-	(21,199)
32	2045	(24,242)	3,145	-	(21,097)
33	2046	(24,063)	3,145	-	(20,918)
34	2047	(23,974)	3,120	-	(20,854)
35	2048 - 2056	(198,398)	-	-	(198,398)
36		**$ (1,172,029)**	**$ 89,091**	**$ (87,076)**	**$ (1,170,013)**

**** Subject to the normalization provisions of the Internal Revenue Code.***
***** Assumes Calculation C Interim Credit beginning September 2019 through December 2020.***
****** Includes a $4,168,278 beginning balance adjustment related to AFUDC approved by the Commission in U-21224.***

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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Witness: BJVanBlarcum
Date: June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Tax Reform Regulatory Liability & Amortization

Case No.: U-20309
Date: March 2025

	(1) Beginning Balance [A]	(1-A) Rate Change Gross-up Adjustment [C]	(2) Amount Refunded	(3) Regulatory Asset (Liability)	(2-A) Regulatory Asset/(Liability) Refunded	(3-A) Remaining Regulatory Asset/ (Liability)	(4) Ending Balance
2019	$ (1,174,181,474)		$ 8,191,439	$ (6,240,769) [D]	$ 6,240,769	$ -	$ (1,159,749,266)
Beginning Balance Adj [B]	$ 4,168,278		$ -	$ -	$ -	$ -	$ (1,155,580,988)
2020	$ (1,155,580,988)		$ 33,772,000	$ (8,706,572) [E]	$ -	$ (8,706,572)	$ (1,113,102,416)
2021	$ (1,113,102,416)		$ 35,750,000	$ (5,569,763) [F]	$ -	$ (5,569,763)	$ (1,071,782,653)
2022	(1,071,782,653)		$ 36,999,000	$ (12,498,566)	$ 1,895,000 [A]	$ (10,603,566)	$ (1,022,285,087)
2023	(1,022,285,087)	2,381,350	$ 41,109,000	$ 2,821,501	$ -	$ 2,821,501	$ (981,616,238)
2024	(981,616,238)	-	$ 42,367,000	$ (1,723,356)	$ -	$ (1,723,356)	$ (937,525,882)

[A] Electric information contained herein includes amounts associated with transmission assets, which are subject to rate regulation by the Federal Energy Regulatory Commission ("FERC"). On September 13, 2022, FERC issued a final order in Docket #ER22-2597-000 requiring $1,895,000 of TCJA-related excess deferred federal income taxes associated with transmission assets be refunded to transmission customers. This amount is reflected in column 2-A and reduced the Regulatory Asset/(Liability) due to customers as it will be refunded subject to the FERC order.

[B] In its original U-20309 filing, the Company inadvertently included in its unprotected plant balance a remeasurement of excess deferred taxes associated with AFUDC timing differences. A subsequent reconcilation of the 2019 TCJA balance highlighted this discrepancy. The Company reflected this proposed change in Case No. U-21224 and the Commission subsequently approved the adjustment in it's January 19, 2023 order.

[C] Gross-up change to the regulatory liability balance due to a statutory or apportionment rate change.

[D] Included in Case No. U-21224.

[E] Included in Case No. U-21389

[F] Included in Case No. U-21585