



DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1221

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September 12, 2023

Lisa Felice
Acting Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
MPSC Case No. U-21297

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Official Exhibits of the DTE Electric Company admitted into the record on September 4-6, 2024 and September 9-10, 2024:

Exhibits A-1 thru A-6 and A-11 thru A-20

If you have any questions or concerns with this filing, please contact me at the above referenced number.

Respectfully submitted,

Estella R. Branson

Digitally signed by Estella R.
Branson
Date: 2024.09.12 12:14:56 -04'00'

Estella R. Branson
Senior Paralegal

Enclosure

Michigan Public Service Commission
DTE Electric Company
Historical Revenue Deficiency (Sufficiency)
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-1
Schedule: A1
Witness: K. M. Vangilder
Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exh. A-2, Sch. B1	\$ 20,116,777
2	Adjusted Net Operating Income	Exh. A-3, Sch. C1	\$ 1,131,985
3	Overall Rate of Return	Line 2 ÷ Line 1	5.63%
4	Required Rate of Return	Exh. A-4, Sch. D1	5.33%
5	Income Requirements	Line 1 x Line 4	\$ 1,072,345
6	Income Deficiency / (Sufficiency)	Line 5 - Line 2	\$ (59,640)
7	Revenue Conversion Factor	Exh. A-3, Sch. C2	<u>1.3496</u>
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	<u>\$ (80,492)</u>

Michigan Public Service Commission
DTE Electric Company
Historical Financial Metrics* - Financial Basis
For the Period Ended December 31, 2022
(\$Millions)

Case No.: U-21534
 Exhibit: A-1
 Schedule: A2
 Witness: T. J. Lepczyk
 Page: 1 of 6

Line No.	(a) Description	(b) 2018	(c) 2019	(d) 2020	(e) 2021	(f) 2022
<u>Return on Equity</u>						
1	Operating Revenue	5,298	5,224	5,506	5,809	6,397
2	Operating Expenses	(4,164)	(4,111)	(4,282)	(4,540)	(5,078)
3	Pre-Tax Operating Income	1,134	1,113	1,224	1,269	1,319
4	Income Taxes	(193)	(138)	(109)	(104)	(26)
5	Net Operating Income	941	975	1,115	1,165	1,293
6	Other Income and Deductions, incl AFUDC	6	54	(6)	36	32
7	Interest Charges	(283)	(313)	(331)	(335)	(370)
8	Preferred Stock Dividends	-	-	-	-	-
9	Net Income	664	716	778	866	955
10	Average Common Equity	6,529	6,994	7,633	8,487	9,299
11	Earned Rate of Return on Common Equity	10.2%	10.2%	10.2%	10.2%	10.3%
12	Authorized Rate of Return on Common Equity	<u>9.9%</u>	<u>9.9%</u>	<u>9.9%</u>	<u>9.9%</u>	<u>9.9%</u>
<u>EBIT Interest Coverage Ratio</u>						
13	Pre-Tax Operating Income	1,134	1,113	1,224	1,269	1,319
14	Other Income and Deductions, incl AFUDC	6	54	(6)	36	32
15	AFUDC - equity	(19)	(22)	(23)	(25)	(26)
16	Total EBIT	1,121	1,145	1,195	1,280	1,325
17	Interest Charges	283	313	331	335	370
18	EBIT Interest Coverage Ratio	4.0	3.7	3.6	3.8	3.6

Michigan Public Service Commission
DTE Electric Company
Historical Financial Metrics* - Financial Basis
For the Period Ended December 31, 2022

Case No.: U-21534
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Witness: T. J. Lepczyk
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	2018	2019	2020	2021	2022
<u>EBITDA Interest Coverage Ratio</u>						
19	Total EBIT	1,121	1,145	1,195	1,280	1,325
20	Depreciation and Amortization	836	946	1,043	1,109	1,204
21	Total EBITDA	1,957	2,091	2,238	2,389	2,529
22	Interest Charges	283	313	331	335	370
23	EBITDA Interest Coverage Ratio	6.9	6.7	6.8	7.1	6.8
<u>Funds Flow from Operations (FFO) Interest Coverage Ratio</u>						
24	Net Income	664	716	778	866	955
25	Depreciation and Amortization	836	946	1,043	1,109	1,204
26	Deferred Income Tax	189	97	89	122	25
27	AFUDC	(19)	(22)	(23)	(25)	(26)
28	Other Major Recurring Non-Cash Items	-	-	-	-	-
29	Interest Paid	283	313	331	335	370
30	Subtotal	1,953	2,050	2,218	2,407	2,528
31	Interest Charges	283	313	331	335	370
32	FFO Interest Coverage Ratio	6.9	6.5	6.7	7.2	6.8
<u>Overall Fixed Charge Coverage Ratio</u>						
33	Net Income	664	716	778	866	955
34	Interest Charges	283	313	331	335	370
35	Subtotal Numerator	947	1,029	1,109	1,201	1,325
36	Interest Charges	283	313	331	335	370
37	Preferred Stock Dividends	-	-	-	-	-
38	Subtotal Denominator	283	313	331	335	370
39	Overall Fixed Charge Coverage Ratio	3.3	3.3	3.4	3.6	3.6

Michigan Public Service Commission
DTE Electric Company
Historical Financial Metrics* - Financial Basis
For the Period Ended December 31, 2022

Case No.: U-21534
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	2018	2019	2020	2021	2022
<u>Cash Flow Coverage of Dividends Ratio</u>						
40	Net Income	664	716	778	866	955
41	Depreciation and Amortization	836	946	1,043	1,109	1,204
42	Deferred Taxes	189	97	89	122	25
43	Subtotal	1,689	1,759	1,910	2,097	2,184
44	Common Dividends	461	494	539	588	763
45	Cash Flow Coverage of Dividends Ratio	3.7	3.6	3.5	3.6	2.9
<u>Common Dividends Payout Ratio</u>						
46	Common Dividends	461	494	539	588	763
47	Net Income	664	716	778	866	955
48	Common Dividends Payout Ratio	69%	69%	69%	68%	80%
<u>Permanent Capitalization</u>						
49	Long Term Debt	6,542	7,184	8,242	8,913	9,491
50	Preferred Stock	-	-	-	-	-
51	Common Equity	6,793	7,195	8,070	8,903	9,695
52	Total Permanent Capital	13,335	14,379	16,312	17,816	19,186
53	Long Term Debt	49.1%	50.0%	50.5%	50.0%	49.5%
54	Preferred Stock	- %	- %	- %	- %	- %
55	Common Equity	50.9%	50.0%	49.5%	50.0%	50.5%
56	Total Permanent Capital	100.0%	100.0%	100.0%	100.0%	100.0%

Michigan Public Service Commission
DTE Electric Company
Historical Financial Metrics* - Ratemaking Basis
For the Period Ended December 31, 2022
(\$Millions)

Case No.: U-21534
Exhibit: A-1
Schedule: A2
Witness: T. J. Lepczyk
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Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)
		Calendar Year				
		2018	2019	2020	2021	2022
<u>Return on Equity</u>						
57	Operating Revenue	5,286	5,218	5,502	5,804	6,362
58	Operating Expenses	(4,145)	(4,081)	(4,225)	(4,521)	(5,018)
59	Pre-Tax Operating Income	1,141	1,138	1,277	1,284	1,345
60	Income Taxes	(191)	(134)	(130)	(106)	(34)
61	Net Operating Income	951	1,003	1,147	1,177	1,310
62	Other Income and Deductions, incl AFUDC	(6)	23	(40)	22	16
63	Interest Charges	(280)	(310)	(328)	(333)	(364)
64	Preferred Stock Dividends	-	-	-	-	-
65	Net Income	665	715	779	866	962
66	Return Assignable to JDITC	(7)	(8)	(8)	(8)	(9)
67	Net Income Available for Common	658	708	771	859	953
68	Less: Energy Waste Reduction	(17)	(17)	(20)	(29)	(28)
69	Less: Renewable Energy Program	(51)	(62)	(74)	(107)	(122)
70	Net Income Available for Common less EWR and REP	591	629	677	722	803
71	Average Common Equity	6,533	6,999	7,638	8,492	9,309
72	Less: Energy Waste Reduction	(9)	(11)	(15)	(20)	(19)
73	Less: Renewable Energy Program	(503)	(561)	(667)	(947)	(1,154)
74	Average Common Equity less EWR and REP	6,022	6,427	6,956	7,525	8,136
75	Earned Rate of Return on Common Equity	9.8%	9.8%	9.7%	9.6%	9.9%
76	Authorized Rate of Return on Common Equity	10.0%	9.9%	9.9%	9.9%	9.9%
77	Net Income Available for Common less EWR and REP	591	629	677	722	803
78	Less: Weather Warmer/(Colder) than Normal	105	28	21	32	24
79	Net Income Available for Common-WN	486	601	656	691	779
80	Average Common Equity	6,022	6,427	6,956	7,525	8,136
81	Earned Rate of Return on Common Equity -WN	8.1%	9.3%	9.4%	9.2%	9.6%
<u>EBIT Interest Coverage Ratio</u>						
82	Pre-Tax Operating Income	1,141	1,138	1,277	1,284	1,345
83	Other Income and Deductions, incl AFUDC	(6)	23	(40)	22	16
84	AFUDC - equity	(19)	(22)	(23)	(25)	(26)
85	Total EBIT	1,122	1,115	1,254	1,259	1,318
86	Interest Charges	280	310	328	333	364
87	EBIT Interest Coverage Ratio	4.0	3.6	3.8	3.8	3.6

Michigan Public Service Commission
DTE Electric Company
Historical Financial Metrics* - Ratemaking Basis
For the Period Ended December 31, 2022

Case No.: U-21534
Exhibit: A-1
Schedule: A2
Witness: T. J. Lepczyk
Page: 5 of 6

Line No.	Description	(a)	(b)	(c)	(d)	(e)	(f)
		Calendar Year					
		2018	2019	2020	2021	2022	
<u>EBITDA Interest Coverage Ratio</u>							
88	Total EBIT	1,122	1,115	1,254	1,259	1,318	
89	Depreciation and Amortization	826	939	1,032	1,096	1,161	
90	Total EBITDA	1,948	2,054	2,286	2,355	2,479	
91	Interest Charges	280	310	328	333	364	
92	EBITDA Interest Coverage Ratio	7.0	6.6	7.0	7.1	6.8	
<u>Funds Flow from Operations (FFO) Interest Coverage Ratio</u>							
93	Net Income	665	715	779	866	962	
94	Depreciation and Amortization	826	939	1,032	1,096	1,161	
95	Deferred Income Tax	190	96	89	123	29	
96	AFUDC	(19)	(22)	(23)	(25)	(26)	
97	Other Major Recurring Non-Cash Items	-	-	-	-	-	
98	Interest Paid	280	310	328	333	364	
99	Subtotal	1,941	2,038	2,205	2,394	2,489	
100	Interest Charges	280	310	328	333	364	
101	FFO Interest Coverage Ratio	6.9	6.6	6.7	7.2	6.8	
<u>Overall Fixed Charge Coverage Ratio</u>							
102	Net Income	665	715	779	866	962	
103	Interest Charges	280	310	328	333	364	
104	Subtotal Numerator	945	1,026	1,107	1,200	1,326	
105	Interest Charges	280	310	328	333	364	
106	Preferred Stock Dividends	-	-	-	-	-	
107	Subtotal Denominator	280	310	328	333	364	
108	Overall Fixed Charge Coverage Ratio	3.4	3.3	3.4	3.6	3.6	

Michigan Public Service Commission
DTE Electric Company
Historical Financial Metrics* - Ratemaking Basis
For the Period Ended December 31, 2022

Case No.: U-21534
Exhibit: A-1
Schedule: A2
Witness: T. J. Lepczyk
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Line No.	Description	(a)	(b)	(c)	(d)	(e)	(f)
		Calendar Year					
		2018	2019	2020	2021	2022	
<u>Cash Flow Coverage of Dividends Ratio</u>							
109	Net Income	665	715	779	866	962	
110	Depreciation and Amortization	826	939	1,032	1,096	1,161	
111	Deferred Taxes	190	96	89	123	29	
112	Subtotal	1,680	1,750	1,900	2,085	2,151	
113	Common Dividends	461	494	539	588	762	
114	Cash Flow Coverage of Dividends Ratio	3.6	3.5	3.5	3.5	2.8	
<u>Common Dividends Payout Ratio</u>							
115	Common Dividends	461	494	539	588	762	
116	Net Income	665	715	779	866	962	
117	Common Dividends Payout Ratio	69%	69%	69%	68%	79%	
<u>Permanent Capitalization</u>							
118	Long Term Debt	6,553	7,203	8,270	8,988	9,572	
119	Preferred Stock	-	-	-	-	-	
120	Common Equity	6,798	7,200	8,075	8,909	9,708	
121	Total Permanent Capital	13,350	14,402	16,346	17,897	19,279	
122	Long Term Debt (Excluding Securitization)	49.1%	50.0%	50.6%	50.2%	49.6%	
123	Preferred Stock	- %	- %	- %	- %	- %	
124	Common Equity	50.9%	50.0%	49.4%	49.8%	50.4%	
125	Total Permanent Capital	100.0%	100.0%	100.0%	100.0%	100.0%	

* Each rating agency has its own methodology for calculating financial ratios. The adjustments used by the rating agencies are not readily available. The standard methodology for calculating ratios has been used in the financial metric calculations above.

Michigan Public Service Commission
DTE Electric Company
Historical Rate Base
For the 13-Month Average Period Ended 12/31/2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B1
Witness: K. M. Vangilder
Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Rate Base
1	Plant in Service	Exh. A-2, Sch. B2, L6	24,545,204
2	Plant Held for Future Use	Exh. A-2, Sch. B2, L7	57,100
3	Construction Work in Progress	Exh. A-2, Sch. B2, L8	1,704,966
4	Acquisition Adjustments	Exh. A-2, Sch. B2, L9	<u>100,705</u>
5	Total Utility Plant	Sum Lines 1 thru 4	26,407,974
6	Depreciation Reserve	Exh. A-2, Sch. B3, L6	<u>(7,685,530)</u>
7	Net Utility Plant	Line 5 + Line 6	18,722,444
8	Net Capital Lease Property	Exh. A-2, Sch. B5, Col. (c), L10	8,844
9	Property under Operating Leases	Exh. A-2, Sch. B5, Col. (c), L11	-
10	Net Nuclear Fuel Property	Exh. A-2, Sch. B5, Col. (c), L12	<u>188,783</u>
11	Total Utility Property and Plant	Sum Lines 7 thru 10	18,920,071
12	Less: Capital Lease Obligations	Exh. A-2, Sch. B5, Col. (c), L85 + L100	<u>10,272</u>
13	Net Plant	Line 11 - Line 12	18,909,799
14	Allowance for Working Capital	Exh. A-2, Sch. B5, Col. (d), L119	<u>1,206,978</u>
15	Rate Base	Line 13 + Line 14	<u><u>20,116,777</u></u>

Michigan Public Service Commission
DTE Electric Company
Historical Utility Plant
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-2
 Schedule: B2
 Witness: T. M. Uzenski
 Page: 1 of 1

(a)		(b)	(c)	(d)	(e)
Line		MPSC			
No.	Description	Account Number	Utility Plant (\$000)		Source
			Year End Balance	13 Month Average	
1	Plant in Service	101	22,485,302	22,475,602	
2	Plant Purchased or Sold	102	-	-	
3	Experimental Plant Unclassified	103	-	-	
4	Plant Leased from Others	104	-	-	
5	Completed Construction Not Classified	106	<u>2,098,762</u>	<u>2,069,602</u>	
6	Plant in Service		24,584,064	24,545,204	Exh. A-2, Sch. B5 & B5.1, Col. (c), L4
7	Plant Held for Future Use	105	57,100	57,100	Exh. A-2, Sch. B5 & B5.1, Col. (c), L5
8	Construction Work in Progress	107	1,730,024	1,704,966	Exh. A-2, Sch. B5 & B5.1, Col. (c), L6
9	Acquisition Adjustments	114	<u>97,810</u>	<u>100,705</u>	Exh. A-2, Sch. B5 & B5.1, Col. (c), L7
10	Total Utility Plant		<u>26,468,997</u>	<u>26,407,974</u>	

Michigan Public Service Commission
DTE Electric Company
Historical Depreciation Reserve
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B3
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	Description	Historical Accumulated Provision for Depreciation (\$000)		Source
		Year End Balance	13 Month Average	
1	Intangible Plant	329,177		
2	Production Plant	3,146,506		
3	Transmission Plant	3,519		
4	Distribution Plant	3,467,028		
5	General Plant	347,887		
6	Total Historical Depreciation Reserve	7,294,117	7,685,530	Exh. A-2, Sch. B5 & B5.1, Col. (c), L8

Note: Historical Depreciation Reserve is not available by Plant classification for 13 month average

Michigan Public Service Commission
DTE Electric Company
Historical Working Capital
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B4
Witness: T. M. Uzenski
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(a)		(b)		(c)	(d)
Line No.	Description	Working Capital (\$000)		Source	
		Year End Balance	13 Month Average		
1	Total Working Capital	1,110,182	1,206,978	Exh. A-2, Sch. B5 & B5.1, Col. (c), L119	

Michigan Public Service Commission
DTE Electric Company
Historical 13-Month Average Adjusted Balance Sheet
with Classifications
For the 13-Month Average Period Ended 12/31/2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B5
Witness: T. M. Uzensk
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Total 13 Month Avg (1) 12/31/2022	Net Plant	Working Capital	Common Equity	Short-Term Debt	Long-Term Debt	Deferred Taxes	Job Development Investment Tax Credits
1	ASSETS AND OTHER DEBITS								
2	TOTAL UTILITY PLANT AND PROPERTY								
3	TOTAL UTILITY PLANT								
4	Plant in Service	24,545,204	24,545,204	-	-	-	-	-	-
5	Plant Held for Future Use	57,100	57,100	-	-	-	-	-	-
6	Construction Work in Progress	1,704,966	1,704,966	-	-	-	-	-	-
7	Acquisition Adjustments	100,705	100,705	-	-	-	-	-	-
8	Depreciation Reserve	(7,685,530)	(7,685,530)	-	-	-	-	-	-
9	NET UTILITY PLANT	18,722,444	18,722,444	-	-	-	-	-	-
10	Net Capital Lease Property	8,844	8,844	-	-	-	-	-	-
11	Property under Operating Leases	-	-	-	-	-	-	-	-
12	Net Nuclear Fuel Property	188,783	188,783	-	-	-	-	-	-
13	TOTAL UTILITY PLANT AND PROPERTY	18,920,071	18,920,071	-	-	-	-	-	-
14	OTHER PROPERTY AND INVESTMENTS								
15	Non-Utility Property	-	-	-	-	-	-	-	-
16	Non-Current Portion of Allowances	533	-	533	-	-	-	-	-
17	Investment and Special Funds	38,749	-	38,749	-	-	-	-	-
18	Nuclear Decommissioning Trust Funds	-	-	-	-	-	-	-	-
19	TOTAL OTHER PROPERTY & INVESTMENTS	39,282	-	39,282	-	-	-	-	-
20	CURRENT ASSETS								
21	Cash	11,011	-	11,011	-	-	-	-	-
22	Notes Receivable	-	-	-	-	-	-	-	-
23	Notes Receivable-Assoc. Co.	-	-	-	-	-	-	-	-
24	Customer Accounts Receivable	500,991	-	500,991	-	-	-	-	-
25	Other Accounts Receivable	82,804	-	82,804	-	-	-	-	-
26	Other Accounts Receivable-Assoc. Co.	-	-	-	-	-	-	-	-
27	Uncollectible Reserve	(52,834)	-	(52,834)	-	-	-	-	-
28	Unbilled Revenues	275,981	-	275,981	-	-	-	-	-
29	Inventories - Fuel	164,835	-	164,835	-	-	-	-	-
30	Inventories - Material and Supplies	322,862	-	322,862	-	-	-	-	-
31	Prepayments	101,667	-	101,667	-	-	-	-	-
32	Other Current Assets	0	-	0	-	-	-	-	-
33	TOTAL CURRENT ASSETS	1,407,318	-	1,407,318	-	-	-	-	-
34	DEFERRED DEBITS								
35	Unamortized Debt Expense	66,218	-	-	-	-	66,218	-	-
36	Unamortized Loss on Reacquired Debt	35,970	-	35,970	-	-	-	-	-
37	Reg Asset - Fermi 2	-	-	-	-	-	-	-	-
38	Def Debit - Prepaid Pension Asset	636,559	-	636,559	-	-	-	-	-
39	Reg Asset - Recoverable Pension & OPEB FAS 158	0	-	0	-	-	-	-	-
40	Reg Asset - Pension Deferral	3,148	-	3,148	-	-	-	-	-
41	Reg Asset - Monroe	-	-	-	-	-	-	-	-
42	Reg Asset - Ludington	-	-	-	-	-	-	-	-
43	Reg Asset - Transitional Recovery Mechanism (TRM)	-	-	-	-	-	-	-	-
44	Reg Asset - Customer 360	43,917	-	43,917	-	-	-	-	-
45	Reg Asset - Tier 2 Plants	-	-	-	-	-	-	-	-
46	Reg Asset - Residential Income Assistance	2,241	-	2,241	-	-	-	-	-
47	Reg Asset - Program Eval. Review Committee (PERC)	32,473	-	32,473	-	-	-	-	-
48	Reg Asset - Advanced Distribution Management System	11,355	-	11,355	-	-	-	-	-
49	Reg Asset - Charging Forward	7,477	-	7,477	-	-	-	-	-
50	Reg Asset - Enhanced Tree Trimming Program	-	-	-	-	-	-	-	-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	6,494	-	6,494	-	-	-	-	-
52	Reg Asset - Time of Day Deferred Project Costs	152	-	152	-	-	-	-	-
53	Reg Asset - Open	-	-	-	-	-	-	-	-
54	Reg Asset - Pension Capitalized	18,285	-	18,285	-	-	-	-	-
55	Reg Asset - Demand Response	3,610	-	3,610	-	-	-	-	-
56	Reg Asset - Incentive Deferral	66	-	66	-	-	-	-	-
57	Reg Asset - Low Income Assistance Tracker	52	-	52	-	-	-	-	-
58	Reg Asset - Low Income Payment Stability Plan	438	-	438	-	-	-	-	-
59	Reg Asset - TCJA Under Recovery	99	-	99	-	-	-	-	-
60	Reg Asset - OPEN	-	-	-	-	-	-	-	-
61	Def Debit - Preliminary Survey and Investigation Charges	80	-	80	-	-	-	-	-
62	Def Debit - Prepaid OPEB	120,003	-	120,003	-	-	-	-	-
63	Def Debit - Combined Operating License (COL)	-	-	-	-	-	-	-	-
64	Def Debit - EWR Performance Incentive	-	-	-	-	-	-	-	-
65	Def Debit - Misc Tax Related	205,717	-	-	-	-	-	205,717	-
66	Recoverable Income Taxes	14,905	-	-	-	-	-	14,905	-
67	Accumulated Deferred Income Tax Asset	-	-	-	-	-	-	-	-
68	Other Deferred Debits	23,399	-	23,399	-	-	-	-	-
69	TOTAL DEFERRED DEBITS	1,232,659	-	945,820	-	-	66,218	220,622	-
70	TOTAL ASSETS AND OTHER DEBITS	21,599,330	18,920,071	2,392,419	-	-	66,218	220,622	-

(1) See Exhibit A-2, Schedule B6, Column (c)

Michigan Public Service Commission
DTE Electric Company
Historical 13-Month Average Adjusted Balance Sheet
with Classifications
For the 13-Month Average Period Ended 12/31/2022

Case No.: U-21534
Exhibit: A-2
Schedule: B5
Witness: T. M. Uzensk
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Total 13 Month Avg (1) 12/31/2022	Net Plant	Working Capital	Common Equity	Short-Term Debt	Long-Term Debt	Deferred Taxes	Job Develop Investment Tax Credit
71	LIABILITIES AND OTHER CREDITS								
72	CAPITALIZATION								
73	Long-Term Debt								
74	Bonds Outstanding	8,122,755	-	-	-	-	8,122,755	-	-
75	Net Premium/Discount	(22,251)	-	-	-	-	(22,251)	-	-
76	Total Long-Term Debt	8,100,504	-	-	-	-	8,100,504	-	-
77	Preferred Stock	-	-	-	-	-	-	-	-
78	Common Equity								
79	Common Stock	6,140,301	-	-	6,140,301	-	-	-	-
80	Retained Earnings	1,563,474	-	-	1,563,474	-	-	-	-
81	Other Comprehensive Income	(0)	-	-	(0)	-	-	-	-
82	Total Common Equity	7,703,775	-	-	7,703,775	-	-	-	-
83	TOTAL CAPITALIZATION	15,804,279	-	-	7,703,775	-	8,100,504	-	-
84	NON-CURRENT LIABILITIES								
85	Capital Leases - Non-Current	3,799	3,799	-	-	-	-	-	-
86	Operating Leases - Non-Current	(0)	(0)	-	-	-	-	-	-
87	Accumulated Provision for Injuries and Damages	38,139	-	38,139	-	-	-	-	-
88	Accrued Post Retirement Benefits	(470)	-	(470)	-	-	-	-	-
89	Accrued Pension Liabilities	(0)	-	(0)	-	-	-	-	-
90	Asset Retirement Obligations	-	-	-	-	-	-	-	-
91	Other Non-Current Liabilities	(0)	-	(0)	-	-	-	-	-
92	TOTAL NON-CURRENT LIABILITES	41,468	3,799	37,669	-	-	-	-	-
93	CURRENT LIABILITIES								
94	Short-Term Debt	167,142	-	-	-	167,142	-	-	-
95	Notes Payable - Assoc. Co.	-	-	-	-	-	-	-	-
96	Accounts Payable	576,308	-	576,308	-	-	-	-	-
97	Accounts Payable - Assoc. Co.	73,784	-	73,784	-	-	-	-	-
98	Taxes Payable	5,091	-	5,091	-	-	-	-	-
99	Interest Payable	104,598	-	104,598	-	-	-	-	-
100	Capital Leases - Current	6,474	6,474	-	-	-	-	-	-
101	Operating Leases - Current	-	-	-	-	-	-	-	-
102	Fermi 2 Outage Accrual	11,993	-	11,993	-	-	-	-	-
103	Other Current Liabilities	168,651	-	168,651	-	-	-	-	-
104	TOTAL CURRENT LIABILITIES	1,114,042	6,474	940,426	-	167,142	-	-	-
105	DEFERRED CREDITS								
106	Regulatory Liab-Renewable Energy Program	-	-	-	-	-	-	-	-
107	Regulatory Liab-Energy Optimization	-	-	-	-	-	-	-	-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	117,355	-	117,355	-	-	-	-	-
109	Regulatory Liab-OPEB Capitalized	63,042	-	63,042	-	-	-	-	-
110	Regulatory Liab- Pension Capitalized	-	-	-	-	-	-	-	-
111	Regulatory Liab- Negative Pension	-	-	-	-	-	-	-	-
112	Fermi 2 Decommissioning	-	-	-	-	-	-	-	-
113	Accumulated Deferred Income Taxes	2,853,174	-	-	-	-	-	2,853,174	-
114	Accumulated Deferred Investment Tax Credit	32,836	-	-	-	-	-	-	32,836
115	Tax Reform Reg Liab-Refundable Income Taxes	1,546,186	-	-	-	-	-	1,546,186	-
116	Other Deferred Credits	26,949	-	26,949	-	-	-	-	-
117	TOTAL DEFERRED CREDITS	4,639,541	-	207,345	-	-	-	4,399,359	32,836
118	TOTAL LIABILITIES AND OTHER CREDITS	21,599,330	10,272	1,185,441	7,703,775	167,142	8,100,504	4,399,359	32,836
119	TOTAL ASSETS - TOTAL LIABILITIES	(0)	18,909,799	1,206,978	(7,703,775)	(167,142)	(8,034,286)	(4,178,738)	(32,836)

(1) See Exhibit A-2, Schedule B6, Column (c)

Michigan Public Service Commission
DTE Electric Company
Historical Year-End Adjusted Balance Sheet
with Classifications
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B5.1
Witness: T. M. Uzenski
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Total Year End (1) 12/31/2022	Net Plant	Working Capital	Common Equity	Short-Term Debt	Long-Term Debt	Deferred Taxes	Job Development Investment Tax Credits
1	ASSETS AND OTHER DEBITS								
2	TOTAL UTILITY PLANT AND PROPERTY								
3	TOTAL UTILITY PLANT								
4	Plant in Service	24,584,064	24,584,064	-	-	-	-	-	-
5	Plant Held for Future Use	57,100	57,100	-	-	-	-	-	-
6	Construction Work in Progress	1,730,024	1,730,024	-	-	-	-	-	-
7	Acquisition Adjustments	97,810	97,810	-	-	-	-	-	-
8	Depreciation Reserve	(7,294,117)	(7,294,117)	-	-	-	-	-	-
9	NET UTILITY PLANT	19,174,880	19,174,880	-	-	-	-	-	-
10	Net Capital Lease Property	6,051	6,051	-	-	-	-	-	-
11	Property under Operating Leases	-	-	-	-	-	-	-	-
12	Net Nuclear Fuel Property	162,597	162,597	-	-	-	-	-	-
13	TOTAL UTILITY PLANT AND PROPERTY	19,343,528	19,343,528	-	-	-	-	-	-
14	OTHER PROPERTY AND INVESTMENTS								
15	Non-Utility Property	-	-	-	-	-	-	-	-
16	Non-Current Portion of Allowances	499	-	499	-	-	-	-	-
17	Investment and Special Funds	39,762	-	39,762	-	-	-	-	-
18	Nuclear Decommissioning Trust Funds	0	-	0	-	-	-	-	-
19	TOTAL OTHER PROPERTY & INVESTMENTS	40,262	-	40,262	-	-	-	-	-
20	CURRENT ASSETS								
21	Cash	14,562	-	14,562	-	-	-	-	-
22	Notes Receivable	-	-	-	-	-	-	-	-
23	Notes Receivable-Assoc. Co.	-	-	-	-	-	-	-	-
24	Customer Accounts Receivable	487,691	-	487,691	-	-	-	-	-
25	Other Accounts Receivable	76,246	-	76,246	-	-	-	-	-
26	Other Accounts Receivable-Assoc. Co.	-	-	-	-	-	-	-	-
27	Uncollectible Reserve	(48,870)	-	(48,870)	-	-	-	-	-
28	Unbilled Revenues	287,081	-	287,081	-	-	-	-	-
29	Inventories - Fuel	167,499	-	167,499	-	-	-	-	-
30	Inventories - Material and Supplies	330,816	-	330,816	-	-	-	-	-
31	Prepayments	66,313	-	66,313	-	-	-	-	-
32	Other Current Assets	0	-	0	-	-	-	-	-
33	TOTAL CURRENT ASSETS	1,381,337	-	1,381,337	-	-	-	-	-
34	DEFERRED DEBITS								
35	Unamortized Debt Expense	65,319	-	-	-	-	65,319	-	-
36	Unamortized Loss on Reacquired Debt	34,377	-	34,377	-	-	-	-	-
37	Reg Asset - Fermi 2	0	-	0	-	-	-	-	-
38	Def Debit - Prepaid Pension Asset	609,853	-	609,853	-	-	-	-	-
39	Reg Asset - Recoverable Pension & OPEB FAS 158	(0)	-	(0)	-	-	-	-	-
40	Reg Asset - Pension Deferral	40,930	-	40,930	-	-	-	-	-
41	Reg Asset - Monroe	-	-	-	-	-	-	-	-
42	Reg Asset - Ludington	-	-	-	-	-	-	-	-
43	Reg Asset - Transitional Recovery Mechanism (TRM)	-	-	-	-	-	-	-	-
44	Reg Asset - Customer 360	41,797	-	41,797	-	-	-	-	-
45	Reg Asset - Tier 2 Plants	-	-	-	-	-	-	-	-
46	Reg Asset - Residential Income Assistance	3,747	-	3,747	-	-	-	-	-
47	Reg Asset - Program Eval. Review Committee (PERC)	25,620	-	25,620	-	-	-	-	-
48	Reg Asset - Advanced Distribution Management System	13,849	-	13,849	-	-	-	-	-
49	Reg Asset - Charging Forward	11,193	-	11,193	-	-	-	-	-
50	Reg Asset - Enhanced Tree Trimming Program	-	-	-	-	-	-	-	-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	6,489	-	6,489	-	-	-	-	-
52	Reg Asset – Time of Day Deferred Project Costs	1,979	-	1,979	-	-	-	-	-
53	Reg Asset – Open	-	-	-	-	-	-	-	-
54	Reg Asset - Pension Capitalized	32,418	-	32,418	-	-	-	-	-
55	Reg Asset - Demand Response	3,715	-	3,715	-	-	-	-	-
56	Reg Asset - Incentive Deferral	856	-	856	-	-	-	-	-
57	Reg Asset - Low Income Assistance Tracker	24	-	24	-	-	-	-	-
58	Reg Asset - Low Income Payment Stability Plan	1,043	-	1,043	-	-	-	-	-
59	Reg Asset - TCJA Under Recovery	400	-	400	-	-	-	-	-
60	Reg Asset - OPEN	-	-	-	-	-	-	-	-
61	Def Debit - Preliminary Survey and Investigation Charges	80	-	80	-	-	-	-	-
62	Def Debit - Prepaid OPEB	129,128	-	129,128	-	-	-	-	-
63	Def Debit - Combined Operating License (COL)	-	-	-	-	-	-	-	-
64	Def Debit - EWR Performance Incentive	-	-	-	-	-	-	-	-
65	Def Debit - Misc Tax Related	203,030	-	-	-	-	-	203,030	-
66	Recoverable Income Taxes	13,715	-	-	-	-	-	13,715	-
67	Accumulated Deferred Income Tax Asset	-	-	-	-	-	-	-	-
68	Other Deferred Debits	27,550	-	27,550	-	-	-	-	-
69	TOTAL DEFERRED DEBITS	1,267,112	-	985,048	-	-	65,319	216,745	-
70	TOTAL ASSETS AND OTHER DEBITS	22,032,240	19,343,528	2,406,647	-	-	65,319	216,745	-

(1) See Exhibit A-2, Schedule B6, Column (b)

Michigan Public Service Commission
DTE Electric Company
Historical Year-End Adjusted Balance Sheet
with Classifications
For the Period Ended December 31, 2022
(\$000's)

Case No.: U-21534
Exhibit: A-2
Schedule: B5.1
Witness: T. M. Uzenski
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Total Year End (1) 12/31/2022	Net Plant	Working Capital	Common Equity	Short-Term Debt	Long-Term Debt	Deferred Taxes	Job Development Investment Tax Credits
71	LIABILITIES AND OTHER CREDITS								
72	CAPITALIZATION								
73	Long-Term Debt								
74	Bonds Outstanding	7,920,135	-	-	-	-	7,920,135	-	-
75	Net Premium/Discount	(22,222)	-	-	-	-	(22,222)	-	-
76	Total Long-Term Debt	7,897,913	-	-	-	-	7,897,913	-	-
77	Preferred Stock	-	-	-	-	-	-	-	-
78	Common Equity								
79	Common Stock	6,601,958	-	-	6,601,958	-	-	-	-
80	Retained Earnings	1,531,387	-	-	1,531,387	-	-	-	-
81	Other Comprehensive Income	(0)	-	-	(0)	-	-	-	-
82	Total Common Equity	8,133,345	-	-	8,133,345	-	-	-	-
83	TOTAL CAPITALIZATION	16,031,258	-	-	8,133,345	-	7,897,913	-	-
84	NON-CURRENT LIABILITIES								
85	Capital Leases - Non-Current	545	545	-	-	-	-	-	-
86	Operating Leases - Non-Current	-	-	-	-	-	-	-	-
87	Accumulated Provision for Injuries and Damages	38,217	-	38,217	-	-	-	-	-
88	Accrued Post Retirement Benefits	0	-	0	-	-	-	-	-
89	Accrued Pension Liabilities	(0)	-	(0)	-	-	-	-	-
90	Asset Retirement Obligations	(0)	-	(0)	-	-	-	-	-
91	Other Non-Current Liabilities	(0)	-	(0)	-	-	-	-	-
92	TOTAL NON-CURRENT LIABILITIES	38,761	545	38,217	-	-	-	-	-
93	CURRENT LIABILITIES								
94	Short-Term Debt	208,303	-	-	-	208,303	-	-	-
95	Notes Payable - Assoc. Co.	-	-	-	-	-	-	-	-
96	Accounts Payable	636,531	-	636,531	-	-	-	-	-
97	Accounts Payable - Assoc. Co.	73,333	-	73,333	-	-	-	-	-
98	Taxes Payable	10,819	-	10,819	-	-	-	-	-
99	Interest Payable	104,161	-	104,161	-	-	-	-	-
100	Capital Leases - Current	6,504	6,504	-	-	-	-	-	-
101	Operating Leases - Current	-	-	-	-	-	-	-	-
102	Fermi 2 Outage Accrual	17,423	-	17,423	-	-	-	-	-
103	Other Current Liabilities	182,447	-	182,447	-	-	-	-	-
104	TOTAL CURRENT LIABILITIES	1,239,522	6,504	1,024,715	-	208,303	-	-	-
105	DEFERRED CREDITS								
106	Regulatory Liab-Renewable Energy Program	-	-	-	-	-	-	-	-
107	Regulatory Liab-Energy Optimization	-	-	-	-	-	-	-	-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	128,416	-	128,416	-	-	-	-	-
109	Regulatory Liab-OPEB Capitalized	72,629	-	72,629	-	-	-	-	-
110	Regulatory Liab- Pension Capitalized	-	-	-	-	-	-	-	-
111	Regulatory Liab- Negative Pension	-	-	-	-	-	-	-	-
112	Fermi 2 Decommissioning	0	-	0	-	-	-	-	-
113	Accumulated Deferred Income Taxes	3,001,595	-	-	-	-	-	3,001,595	-
114	Accumulated Deferred Investment Tax Credit	32,611	-	-	-	-	-	-	32,611
115	Tax Reform Reg Liab-Refundable Income Taxes	1,454,958	-	-	-	-	-	1,454,958	-
116	Other Deferred Credits	32,489	-	32,489	-	-	-	-	-
117	TOTAL DEFERRED CREDITS	4,722,698	-	233,534	-	-	-	4,456,553	32,611
118	TOTAL LIABILITIES AND OTHER CREDITS	22,032,240	7,049	1,296,465	8,133,345	208,303	7,897,913	4,456,553	32,611
119	TOTAL ASSETS - TOTAL LIABILITIES	(0)	19,336,479	1,110,182	(8,133,345)	(208,303)	(7,832,594)	(4,239,808)	(32,611)

(1) See Exhibit A-2, Schedule B6, Column (b)

Michigan Public Service Commission
DTE Electric Company
Historical Adjusted Balance Sheet - Year Ended and 13 Month Average
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B6
Witness: T. M. Uzenski
Page: 1 of 2

Line No.	(a) Description	(b) Year-Ended 12/31/2022 Balance (1)	(c) 13 Month Avg 12/31/2022 Balance (2)
1	ASSETS AND OTHER DEBITS		
2	TOTAL UTILITY PLANT AND PROPERTY		
3	TOTAL UTILITY PLANT		
4	Plant in Service	24,584,064	24,545,204
5	Plant Held for Future Use	57,100	57,100
6	Construction Work in Progress	1,730,024	1,704,966
7	Acquisition Adjustments	97,810	100,705
8	Depreciation Reserve	(7,294,117)	(7,685,530)
9	NET UTILITY PLANT	19,174,880	18,722,444
10	Net Capital Lease Property	6,051	8,844
11	Property under Operating Leases	-	-
12	Net Nuclear Fuel Property	162,597	188,783
13	TOTAL UTILITY PLANT AND PROPERTY	19,343,528	18,920,071
14	OTHER PROPERTY AND INVESTMENTS		
15	Non-Utility Property	-	-
16	Non-Current Portion of Allowances	499	533
17	Investment and Special Funds	39,762	38,749
18	Nuclear Decommissioning Trust Funds	0	-
19	TOTAL OTHER PROPERTY & INVESTMENTS	40,262	39,282
20	CURRENT ASSETS		
21	Cash	14,562	11,011
22	Notes Receivable	-	-
23	Notes Receivable-Assoc. Co.	-	-
24	Customer Accounts Receivable	487,691	500,991
25	Other Accounts Receivable	76,246	82,804
26	Other Accounts Receivable-Assoc. Co.	-	-
27	Uncollectible Reserve	(48,870)	(52,834)
28	Unbilled Revenues	287,081	275,981
29	Inventories - Fuel	167,499	164,835
30	Inventories - Material and Supplies	330,816	322,862
31	Prepayments	66,313	101,667
32	Other Current Assets	0	0
33	TOTAL CURRENT ASSETS	1,381,337	1,407,318
34	DEFERRED DEBITS		
35	Unamortized Debt Expense	65,319	66,218
36	Unamortized Loss on Reacquired Debt	34,377	35,970
37	Reg Asset - Fermi 2	0	-
38	Def Debit - Prepaid Pension Asset	609,853	636,559
39	Reg Asset - Recoverable Pension & OPEB FAS 158	(0)	0
40	Reg Asset - Pension Deferral	40,930	3,148
41	Reg Asset - Monroe	-	-
42	Reg Asset - Ludington	-	-
43	Reg Asset - Transitional Recovery Mechanism (TRM)	-	-
44	Reg Asset - Customer 360	41,797	43,917
45	Reg Asset - Tier 2 Plants	-	-
46	Reg Asset - Residential Income Assistance	3,747	2,241
47	Reg Asset - Program Eval. Review Committee (PERC)	25,620	32,473
48	Reg Asset - Advanced Distribution Management System (ADMS)	13,849	11,355
49	Reg Asset - Charging Forward	11,193	7,477
50	Reg Asset - Enhanced Tree Trimming Program	-	-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	6,489	6,494
52	Reg Asset - Time of Day Deferred Project Costs	1,979	152
53	Reg Asset - Open	-	-
54	Reg Asset - Pension Capitalized	32,418	18,285
55	Reg Asset - Demand Response	3,715	3,610
56	Reg Asset - Incentive Deferral	856	66
57	Reg Asset - Low Income Assistance Tracker	24	52
58	Reg Asset - Low Income Payment Stability Plan	1,043	438
59	Reg Asset - TCJA Under Recovery	400	99
60	Reg Asset - OPEN	-	-
61	Def Debit - Preliminary Survey and Investigation Charges	80	80
62	Def Debit - Prepaid OPEB	129,128	120,003
63	Def Debit - Combined Operating License (COL)	-	-
64	Def Debit - EWR Performance Incentive	-	-
65	Def Debit - Misc Tax Related	203,030	205,717
66	Recoverable Income Taxes	13,715	14,905
67	Accumulated Deferred Income Tax Asset	-	-
68	Other Deferred Debits	27,550	23,399
69	TOTAL DEFERRED DEBITS	1,267,112	1,232,659
70	TOTAL ASSETS AND OTHER DEBITS	22,032,240	21,599,330

(1) See Exhibit A-2, Schedule B6.1, Page 1, Column (q)

(2) See Exhibit A-2, Schedule B6.2, Page 1, Column (q)

(3) Certain working capital accounts were normalized to a 13-month average balance. See Exhibit A-2, Schedule B6.1, Column (o).

Michigan Public Service Commission
DTE Electric Company
Historical Adjusted Balance Sheet - Year Ended and 13 Month Average
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-2
 Schedule: B6
 Witness: T. M. Uzenski
 Page: 2 of 2

Line No.	(a) Description	(b)	(c)
		Year-Ended 12/31/2022 Balance (1), (3)	13 Month Avg 12/31/2022 Balance (2)
71	LIABILITIES AND OTHER CREDITS		
72	CAPITALIZATION		
73	Long-Term Debt		
74	Bonds Outstanding	7,920,135	8,122,755
75	Net Premium/Discount	(22,222)	(22,251)
76	Total Long-Term Debt	7,897,913	8,100,504
77	Preferred Stock	-	-
78	Common Equity		
79	Common Stock	6,601,958	6,140,301
80	Retained Earnings	1,531,387	1,563,474
81	Other Comprehensive Income	(0)	(0)
82	Total Common Equity	8,133,345	7,703,775
83	TOTAL CAPITALIZATION	16,031,258	15,804,279
84	NON-CURRENT LIABILITIES		
85	Capital Leases - Non-Current	545	3,799
86	Operating Leases - Non-Current	-	(0)
87	Accumulated Provision for Injuries and Damages	38,217	38,139
88	Accrued Post Retirement Benefits	0	(470)
89	Accrued Pension Liabilities	(0)	(0)
90	Asset Retirement Obligations	(0)	-
91	Other Non-Current Liabilities	(0)	(0)
92	TOTAL NON-CURRENT LIABILITIES	38,761	41,468
93	CURRENT LIABILITIES		
94	Short-Term Debt	208,303	167,142
95	Notes Payable - Assoc. Co.	-	-
96	Accounts Payable	636,531	576,308
97	Accounts Payable - Assoc. Co.	73,333	73,784
98	Taxes Payable	10,819	5,091
99	Interest Payable	104,161	104,598
100	Capital Leases - Current	6,504	6,474
101	Operating Leases - Current	-	-
102	Fermi 2 Outage Accrual	17,423	11,993
103	Other Current Liabilities	182,447	168,651
104	TOTAL CURRENT LIABILITIES	1,239,522	1,114,042
105	DEFERRED CREDITS		
106	Regulatory Liab-Renewable Energy Program	-	-
107	Regulatory Liab-Energy Optimization	-	-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	128,416	117,355
109	Regulatory Liab-OPEB Capitalized	72,629	63,042
110	Regulatory Liab- Pension Capitalized	-	-
111	Regulatory Liab- Negative Pension	-	-
112	Fermi 2 Decommissioning	0	-
113	Accumulated Deferred Income Taxes	3,001,595	2,853,174
114	Accumulated Deferred Investment Tax Credit	32,611	32,836
115	Tax Reform Reg Liab-Refundable Income Taxes	1,454,958	1,546,186
116	Other Deferred Credits	32,489	26,949
117	TOTAL DEFERRED CREDITS	4,722,698	4,639,541
118	TOTAL LIABILITIES AND OTHER CREDITS	22,032,240	21,599,330

(1) See Exhibit A-2, Schedule B6.1, Page 2, Column (q)
 (2) See Exhibit A-2, Schedule B6.2, Page 2, Column (q)

Michigan Public Service Commission
DTE Electric Company
Historical Year End Adjusted Balance Sheet
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B6.1
Witness: T. M. Uzenski
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		For the Period Ended 12/31/2022				Securitized	Tree Trim	Combined	Energy			Eliminate	Eliminate	Eliminate	Other Working	Other	
Line No.	Description	DTE Electric	MERC	Consolidated DTE Electric	Deferred Tax & ITC 1/	Tier 2 Plant	Regulatory Asset	Operating License	Waste Reduction	Renewable Energy	TRM Mechanism	Leases ASC 842	ARO ASC 410-20	Benefits ASC 715	Capital Normalization	Reclasses & Eliminations	Total Electric
1	ASSETS AND OTHER DEBITS																
2	TOTAL UTILITY PLANT AND PROPERTY																
3	TOTAL UTILITY PLANT																
4	Plant in Service	27,796,595	98,320	27,894,915		-			(97,524)	(2,444,906)	-		(724,369)			(44,052)	24,584,064
5	Plant Held for Future Use	57,100	-	57,100													57,100
6	Construction Work in Progress	2,159,250	156	2,159,406					-	(429,453)	-					71	1,730,024
7	Acquisition Adjustments	110,727	-	110,727						(12,917)							97,810
8	Depreciation Reserve	(7,815,813)	(68,340)	(7,884,154)	-	-	-	-	51,724	466,063	-	-	54,491	-	-	17,758	(7,294,117)
9	NET UTILITY PLANT	22,307,858	30,136	22,337,994	-	-	-	-	(45,799)	(2,421,213)	-	-	(669,878)	-	-	(26,224)	19,174,880
10	Net Capital Lease Property	6,051	-	6,051													6,051
11	Property under Operating Leases	54,848	1,240	56,088								(56,088)				-	-
12	Net Nuclear Fuel Property	162,597	-	162,597	-	-	-	-	-	-	-	-	-	-	-	-	162,597
13	TOTAL UTILITY PLANT AND PROPERTY	22,531,355	31,376	22,562,731	-	-	-	-	(45,799)	(2,421,213)	-	(56,088)	(669,878)	-	-	(26,224)	19,343,528
14	OTHER PROPERTY AND INVESTMENTS																
15	Non-Utility Property	7,400	-	7,400												(7,400)	-
16	Non-Current Portion of Allowances	1,926	-	1,926						(1,427)							499
17	Investment and Special Funds	45,532	1,021	46,552									(2,857)			(3,933)	39,762
18	Nuclear Decommissioning Trust Funds	1,821,744	-	1,821,744	-	-	-	-	-	-	-	-	(1,821,744)	-	-	-	0
19	TOTAL OTHER PROPERTY & INVESTMENTS	1,876,602	1,021	1,877,622	-	-	-	-	-	(1,427)	-	-	(1,824,600)	-	-	(11,333)	40,262
20	CURRENT ASSETS																
21	Cash	14,562	-	14,562													14,562
22	Notes Receivable	16,592	-	16,592												(13,880)	-
23	Notes Receivable-Assoc. Co.	31,211	(31,211)	(0)						(2,713)						0	-
24	Customer Accounts Receivable	484,701	894	485,595											2,096		487,691
25	Other Accounts Receivable	76,246	(0)	76,246													76,246
26	Other Accounts Receivable-Assoc. Co.	4,636	-	4,636											(4,636)		-
27	Uncollectible Reserve	(48,870)	-	(48,870)													(48,870)
28	Unbilled Revenues	287,081	-	287,081													287,081
29	Inventories - Fuel	167,347	152	167,499													167,499
30	Inventories - Material and Supplies	322,560	8,256	330,816													330,816
31	Prepayments	70,516	110	70,626												(4,313)	66,313
32	Other Current Assets	420,788	-	420,788	-	-	-	-	-	-	-	-	-	-	-	(420,788)	0
33	TOTAL CURRENT ASSETS	1,847,371	(21,800)	1,825,570	-	-	-	-	-	(2,713)	-	-	-	-	(2,540)	(438,980)	1,381,337
34	DEFERRED DEBITS																
35	Unamortized Debt Expense	65,319	-	65,319													65,319
36	Unamortized Loss on Reacquired Debt	34,377	-	34,377													34,377
37	Reg Asset - Fermi 2	972,202	-	972,202									(972,202)				0
38	Def Debit - Prepaid Pension Asset	-	-	-										609,853			609,853
39	Reg Asset - Recoverable Pension & OPEB FAS 158	1,056,496	-	1,056,496										(1,056,496)			(0)
40	Reg Asset - Pension Deferral	40,930	-	40,930													40,930
41	Reg Asset - Monroe	-	-	-		-											-
42	Reg Asset - Ludington	-	-	-		-											-
43	Reg Asset - Transitional Recovery Mechanism (TRM)	30,391	-	30,391							(30,391)						-
44	Reg Asset - Customer 360	41,797	-	41,797													41,797
45	Reg Asset - Tier 2 Plants	594,081	-	594,081		(594,081)											-
46	Reg Asset - Residential Income Assistance	3,747	-	3,747													3,747
47	Reg Asset - Program Eval. Review Committee (PEF)	25,620	-	25,620													25,620
48	Reg Asset - Advanced Distribution Management Sys	13,849	-	13,849													13,849
49	Reg Asset - Charging Forward	11,193	-	11,193													11,193
50	Reg Asset - Enhanced Tree Trimming Program	90,395	-	90,395			(90,395)										-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	6,489	-	6,489													6,489
52	Reg Asset - Time of Day Deferred Project Costs	1,979	-	1,979													1,979
53	Reg Asset - Open	-	-	-													-
54	Reg Asset - Pension Capitalized	32,418	-	32,418													32,418
55	Reg Asset - Demand Response	3,715	-	3,715													3,715
56	Reg Asset - Incentive Deferral	856	-	856													856
57	Reg Asset - Low Income Assistance Tracker	24	-	24													24
58	Reg Asset - Low Income Payment Stability Plan	1,043	-	1,043													1,043
59	Reg Asset - TCJA Under Recovery	400	-	400													400
60	Reg Asset - OPEN	-	-	-													-
61	Def Debit - Preliminary Survey and Investigation Cha	65,106	-	65,106						(65,027)							80
62	Def Debit - Prepaid OPEB	344,954	-	344,954										(215,826)			129,128
63	Def Debit - Combined Operating License (COL)	64,425	-	64,425		-		(64,425)									-
64	Def Debit - EWR Performance Incentive	69,649	-	69,649					(69,649)								-
65	Def Debit - Misc Tax Related	203,030	-	203,030													203,030
66	Recoverable Income Taxes	13,715	0	13,715													13,715
67	Accumulated Deferred Income Tax Asset	1,080,376	982	1,081,358	(1,081,358)											-	-
68	Other Deferred Debits	32,263	-	32,263	-	-	-	-	-	(400)	-	-	-	-	-	(4,313)	27,550
69	TOTAL DEFERRED DEBITS	4,900,838	982	4,901,820	(1,081,358)	(594,081)	(90,395)	(64,425)	(69,649)	(65,427)	(30,391)	-	(972,202)	(662,468)	-	(4,313)	1,267,112
70	TOTAL ASSETS AND OTHER DEBITS	31,156,165	11,579	31,167,744	(1,081,358)	(594,081)	(90,395)	(64,425)	(115,448)	(2,490,779)	(30,391)	(56,088)	(3,466,681)	(662,468)	(2,540)	(480,850)	22,032,240

1/ Deferred Tax & ITC adjustment sponsored by Witness Wisniewski

Michigan Public Service Commission
DTE Electric Company
Historical Year End Adjusted Balance Sheet
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B6.1
Witness: T. M. Uzenski
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		For the Period Ended 12/31/2022				Securitized	Tree Trim	Combined	Energy	Renewable	TRM	Eliminate	Eliminate	Eliminate	Other Working	Other	
Line No.	Description	DTE Electric	MERC	Consolidated DTE Electric	Deferred Tax & ITC 1/	Tier 2 Plant	Regulatory Asset	Operating License	Waste Reduction	Energy	Mechanism	Leases ASC 842	ARO ASC 410-20	Benefits ASC 715	Capital Normalization	Reclasses & Eliminations	Total Electric
71	LIABILITIES AND OTHER CREDITS																
72	CAPITALIZATION																
73	Long-Term Debt																
74	Bonds Outstanding	9,571,525	-	9,571,525		(297,040)	(45,197)	(32,213)	(15,636)	(1,241,910)	-	(1,576)				(17,818)	7,920,135
75	Net Premium/Discount	(22,222)	-	(22,222)	-	-	-	-	-	-	-	-	-	-	-	-	(22,222)
76	Total Long-Term Debt	9,549,303	-	9,549,303	-	(297,040)	(45,197)	(32,213)	(15,636)	(1,241,910)	-	(1,576)	-	-	-	(17,818)	7,897,913
77	Preferred Stock	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	Common Equity																
79	Common Stock	6,601,957	1	6,601,958													6,601,958
80	Retained Earnings	3,105,809	2	3,105,811		(297,040)	(45,197)	(32,213)	(15,636)	(1,182,748)	-	(1,576)	19,120			(19,134)	1,531,387
81	Other Comprehensive Income	(0)	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	(0)
82	Total Common Equity	9,707,766	3	9,707,769	-	(297,040)	(45,197)	(32,213)	(15,636)	(1,182,748)	-	(1,576)	19,120	-	-	(19,134)	8,133,345
83	TOTAL CAPITALIZATION	19,257,068	3	19,257,072	-	(594,081)	(90,395)	(64,425)	(31,271)	(2,424,659)	-	(3,151)	19,120	-	-	(36,952)	16,031,258
84	NON-CURRENT LIABILITIES																
85	Capital Leases - Non-Current	545	-	545													545
86	Operating Leases - Non-Current	38,519	828	39,347								(39,347)				-	-
87	Accumulated Provision for Injuries and Damages	38,117	100	38,217													38,217
88	Accrued Post Retirement Benefits	275,266	-	275,266										(275,266)			0
89	Accrued Pension Liabilities	387,202	-	387,202										(387,202)			(0)
90	Asset Retirement Obligations	3,220,912	-	3,220,912									(3,220,912)				(0)
91	Other Non-Current Liabilities	4,231	-	4,231	-	-	-	-	-	-	-	-	-	-	-	(4,231)	(0)
92	TOTAL NON-CURRENT LIABILITIES	3,964,792	928	3,965,720	-	-	-	-	-	-	-	(39,347)	(3,220,912)	(662,468)	-	(4,231)	38,761
93	CURRENT LIABILITIES																
94	Short-Term Debt	577,290	-	577,290					(58,344)	21,296	(30,391)		9,629		(2,540)	(308,638)	208,303
95	Notes Payable - Assoc. Co.	26,522	-	26,522												(26,522)	-
96	Accounts Payable	635,559	973	636,531													636,531
97	Accounts Payable - Assoc. Co.	75,573	(2,239)	73,333													73,333
98	Taxes Payable	8,850	1,969	10,819													10,819
99	Interest Payable	104,161	-	104,161													104,161
100	Capital Leases - Current	6,504	-	6,504													6,504
101	Operating Leases - Current	8,926	412	9,338								(9,338)				-	-
102	Fermi 2 Outage Accrual	17,423	-	17,423													17,423
103	Other Current Liabilities	181,615	1,214	182,829	-	-	-	-	-	-	-	(282)	(100)	-	-	0	182,447
104	TOTAL CURRENT LIABILITIES	1,642,424	2,328	1,644,752	-	-	-	-	(58,344)	21,296	(30,391)	(9,620)	9,529	-	(2,540)	(335,160)	1,239,522
105	DEFERRED CREDITS																
106	Regulatory Liab-Renewable Energy Program	21,296	-	21,296						(21,296)							-
107	Regulatory Liab-Energy Optimization	11,305	-	11,305					(11,305)								-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	128,416	-	128,416													128,416
109	Regulatory Liab-OPEB Capitalized	72,629	-	72,629													72,629
110	Regulatory Liab- Pension Capitalized	-	-	-													-
111	Regulatory Liab- Negative Pension	-	-	-													-
112	Fermi 2 Decommissioning	282,140	-	282,140									(282,140)				0
113	Accumulated Deferred Income Taxes	4,030,118	2,528	4,032,646	(968,877)	-	-		(11,848)	47,124	-		7,722			(105,172)	3,001,595
114	Accumulated Deferred Investment Tax Credit	182,389	-	182,389	(112,481)					(37,297)						-	32,611
115	Tax Reform Reg Liab-Refundable Income Taxes	1,529,836	3,750	1,533,586					(2,680)	(75,948)	-		-			-	1,454,958
116	Other Deferred Credits	33,753	2,040	35,793	-	-	-	-	-	-	-	(3,969)	-	-	-	665	32,489
117	TOTAL DEFERRED CREDITS	6,291,881	8,319	6,300,200	(1,081,358)	-	-	-	(25,832)	(87,417)	-	(3,969)	(274,417)	-	-	(104,507)	4,722,698
118	TOTAL LIABILITIES AND OTHER CREDITS	31,156,165	11,579	31,167,744	(1,081,358)	(594,081)	(90,395)	(64,425)	(115,448)	(2,490,779)	(30,391)	(56,088)	(3,466,681)	(662,468)	(2,540)	(480,850)	22,032,240
119	TOTAL ASSETS - TOTAL LIABILITIES	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	(0)

1/ Deferred Tax & ITC adjustment sponsored by Witness Wisniewski

Michigan Public Service Commission
DTE Electric Company
Historical 13-Month Average Adjusted Balance Sheet
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B6.2
Witness: T. M. Uzenski
Page: 1 of 2

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		13-Month Avg Period Ended 12/31/2022 DTE Electric	MERC	Consolidated DTE Electric	Deferred Tax & ITC 1/	Securitized Tier 2 Plant	Tree Trim Regulatory Asset	Combined Operating License	Energy Waste Reduction	Renewable Energy	TRM Mechanism	Eliminate Leases ASC 842	Eliminate ARO ASC 410-20	Eliminate Benefits ASC 715	Other Working Capital Normalization	Other Reclasses & Eliminations	Total Electric
1	ASSETS AND OTHER DEBITS																
2	TOTAL UTILITY PLANT AND PROPERTY																
3	TOTAL UTILITY PLANT																
4	Plant in Service	27,729,667	97,750	27,827,417		-			(98,386)	(2,443,099)	-		(696,675)			(44,052)	24,545,204
5	Plant Held for Future Use	57,100	-	57,100													57,100
6	Construction Work in Progress	2,060,730	188	2,060,918					-	(356,024)	-					71	1,704,966
7	Acquisition Adjustments	114,039	-	114,039						(13,334)							100,705
8	Depreciation Reserve	(8,202,213)	(66,429)	(8,268,642)	-	-	-	-	42,274	428,633	-	-	94,447	-	-	17,758	(7,685,530)
9	NET UTILITY PLANT	21,759,323	31,509	21,790,832	-	-	-	-	(56,112)	(2,383,823)	-	-	(602,228)	-	-	(26,224)	18,722,444
10	Net Capital Lease Property	8,844	-	8,844													8,844
11	Property under Operating Leases	57,906	1,467	59,373								(59,373)				-	-
12	Net Nuclear Fuel Property	188,783	-	188,783	-	-	-	-	-	-	-	-	-	-	-	-	188,783
13	TOTAL UTILITY PLANT AND PROPERTY	22,014,856	32,976	22,047,832	-	-	-	-	(56,112)	(2,383,823)	-	(59,373)	(602,228)	-	-	(26,224)	18,920,071
14	OTHER PROPERTY AND INVESTMENTS																
15	Non-Utility Property	7,177	-	7,177												(7,177)	-
16	Non-Current Portion of Allowances	2,184	-	2,184						(1,652)							533
17	Investment and Special Funds	44,581	993	45,574									(2,864)			(3,960)	38,749
18	Nuclear Decommissioning Trust Funds	1,902,812	-	1,902,812	-	-	-	-	-	-	-	-	(1,902,812)	-	-	-	-
19	TOTAL OTHER PROPERTY & INVESTMENTS	1,956,754	993	1,957,747	-	-	-	-	-	(1,652)	-	-	(1,905,676)	-	-	(11,138)	39,282
20	CURRENT ASSETS																
21	Cash	11,011	-	11,011											-		11,011
22	Notes Receivable	21,143	-	21,143						(2,513)						(18,629)	-
23	Notes Receivable-Assoc. Co.	51,912	(30,526)	21,386												(21,386)	-
24	Customer Accounts Receivable	498,197	1,064	499,261											1,730		500,991
25	Other Accounts Receivable	82,801	3	82,804											-		82,804
26	Other Accounts Receivable-Assoc. Co.	2,891	-	2,891											(2,891)		-
27	Uncollectible Reserve	(52,834)	-	(52,834)											-		(52,834)
28	Unbilled Revenues	275,981	-	275,981											-		275,981
29	Inventories - Fuel	164,112	723	164,835													164,835
30	Inventories - Material and Supplies	317,438	5,424	322,862											-		322,862
31	Prepayments	105,874	105	105,979												(4,313)	101,667
32	Other Current Assets	316,181	-	316,181	-	-	-	-	-	-	-	-	-	-	-	(316,181)	0
33	TOTAL CURRENT ASSETS	1,794,707	(23,206)	1,771,501	-	-	-	-	-	(2,513)	-	-	-	-	(1,161)	(360,509)	1,407,318
34	DEFERRED DEBITS																
35	Unamortized Debt Expense	66,218	-	66,218													66,218
36	Unamortized Loss on Reacquired Debt	35,970	-	35,970													35,970
37	Reg Asset - Fermi 2	828,241	-	828,241									(828,241)				-
38	Def Debit - Prepaid Pension Asset	-	-	-										636,559			636,559
39	Reg Asset - Recoverable Pension & OPEB FAS 158	1,050,872	-	1,050,872										(1,050,872)			0
40	Reg Asset - Pension Deferral	3,148	-	3,148													3,148
41	Reg Asset - Monroe	-	-	-		-											-
42	Reg Asset - Ludington	-	-	-		-											-
43	Reg Asset - Transitional Recovery Mechanism (TRM)	22,382	-	22,382							(22,382)						-
44	Reg Asset - Customer 360	43,917	-	43,917													43,917
45	Reg Asset - Tier 2 Plants	199,686	-	199,686		(199,686)											-
46	Reg Asset - Residential Income Assistance	2,241	-	2,241													2,241
47	Reg Asset - Program Eval. Review Committee (PER)	32,473	-	32,473													32,473
48	Reg Asset - Advanced Distribution Management Syst	11,355	-	11,355													11,355
49	Reg Asset - Charging Forward	7,477	-	7,477													7,477
50	Reg Asset - Enhanced Tree Trimming Program	105,753	-	105,753			(105,753)										-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	6,494	-	6,494													6,494
52	Reg Asset - Time of Day Deferred Project Costs	152	-	152													152
53	Reg Asset - Open	-	-	-													-
54	Reg Asset - Pension Capitalized	18,285	-	18,285													18,285
55	Reg Asset - Demand Response	3,610	-	3,610													3,610
56	Reg Asset - Incentive Deferral	66	-	66													66
57	Reg Asset - Low Income Assistance Tracker	52	-	52													52
58	Reg Asset - Low Income Payment Stability Plan	438	-	438													438
59	Reg Asset - TCJA Under Recovery	99	-	99													99
60	Reg Asset - OPEN	-	-	-													-
61	Def Debit - Preliminary Survey and Investigation Char	49,319	-	49,319						(49,240)							80
62	Def Debit - Prepaid OPEB	418,001	-	418,001										(297,998)			120,003
63	Def Debit - Combined Operating License (COL)	66,872	-	66,872			-	(66,872)									-
64	Def Debit - EWR Performance Incentive	50,984	-	50,984					(50,984)								-
65	Def Debit - Misc Tax Related	205,717	-	205,717													205,717
66	Recoverable Income Taxes	14,905	0	14,905													14,905
67	Accumulated Deferred Income Tax Asset	1,008,037	902	1,008,939	(1,008,939)												-
68	Other Deferred Debits	31,736	-	31,736	-	-	-	-	-	(1,785)	-	-	-	-	-	(6,552)	23,399
69	TOTAL DEFERRED DEBITS	4,284,502	902	4,285,404	(1,008,939)	(199,686)	(105,753)	(66,872)	(50,984)	(51,025)	(22,382)	-	(828,241)	(712,311)	-	(6,552)	1,232,659
70	TOTAL ASSETS AND OTHER DEBITS	30,050,819	11,665	30,062,483	(1,008,939)	(199,686)	(105,753)	(66,872)	(107,097)	(2,439,013)	(22,382)	(59,373)	(3,336,145)	(712,311)	(1,161)	(404,422)	21,599,330

1/ Deferred Tax & ITC adjustment sponsored by Witness Wisniewski

Michigan Public Service Commission
DTE Electric Company
Historical 13-Month Average Adjusted Balance Sheet
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-2
Schedule: B6.2
Witness: T. M. Uzenski
Page: 2 of 2

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		13-Month Avg Period Ended 12/31/2022 DTE Electric	MERC	Consolidated DTE Electric	Deferred Tax & ITC 1/	Securitized Tier 2 Plant	Tree Trim Regulatory Asset	Combined Operating License	Energy Waste Reduction	Renewable Energy	TRM Mechanism	Eliminate Leases ASC 842	Eliminate ARO ASC 410-20	Eliminate Benefits ASC 715	Other Working Capital Normalization	Other Reclasses & Eliminations	Total Electric
71	LIABILITIES AND OTHER CREDITS																
72	CAPITALIZATION																
73	Long-Term Debt																
74	Bonds Outstanding	9,536,448	-	9,536,448		(99,843)	(52,876)	(33,436)	(19,392)	(1,188,826)	-	(1,469)				(17,850)	8,122,755
75	Net Premium/Discount	(22,251)	-	(22,251)	-	-	-	-	-	-	-	-	-	-	-	-	(22,251)
76	Total Long-Term Debt	9,514,197	-	9,514,197	-	(99,843)	(52,876)	(33,436)	(19,392)	(1,188,826)	-	(1,469)	-	-	-	(17,850)	8,100,504
77	Preferred Stock	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	Common Equity																
79	Common Stock	6,140,300	1	6,140,301													6,140,301
80	Retained Earnings	2,903,046	2	2,903,048		(99,843)	(52,876)	(33,436)	(19,392)	(1,132,193)	-	(1,469)	18,530			(18,894)	1,563,474
81	Other Comprehensive Income	(0)	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	(0)
82	Total Common Equity	9,043,346	3	9,043,349	-	(99,843)	(52,876)	(33,436)	(19,392)	(1,132,193)	-	(1,469)	18,530	-	-	(18,894)	7,703,775
83	TOTAL CAPITALIZATION	18,557,542	3	18,557,545	-	(199,686)	(105,753)	(66,872)	(38,784)	(2,321,019)	-	(2,939)	18,530	-	-	(36,744)	15,804,279
84	NON-CURRENT LIABILITIES																
85	Capital Leases - Non-Current	3,799	-	3,799													3,799
86	Operating Leases - Non-Current	41,288	1,022	42,310								(42,310)				-	(0)
87	Accumulated Provision for Injuries and Damages	38,085	54	38,139													38,139
88	Accrued Post Retirement Benefits	330,692	-	330,692										(331,161)			(470)
89	Accrued Pension Liabilities	381,150	-	381,150										(381,150)			(0)
90	Asset Retirement Obligations	3,086,422	-	3,086,422									(3,086,422)				-
91	Other Non-Current Liabilities	58,564	-	58,564	-	-	-	-	-	-	-	-	-	-	-	(58,564)	(0)
92	TOTAL NON-CURRENT LIABILITES	3,939,999	1,076	3,941,075	-	-	-	-	-	-	-	(42,310)	(3,086,422)	(712,311)	-	(58,564)	41,468
93	CURRENT LIABILITES																
94	Short-Term Debt	348,184	-	348,184					(16,767)	20,780	(22,382)		19,139		(1,161)	(180,651)	167,142
95	Notes Payable - Assoc. Co.	50,100	-	50,100												(50,100)	-
96	Accounts Payable	575,127	1,181	576,308											-		576,308
97	Accounts Payable - Assoc. Co.	75,084	(1,299)	73,784											-		73,784
98	Taxes Payable	3,517	1,574	5,091													5,091
99	Interest Payable	104,598	-	104,598													104,598
100	Capital Leases - Current	6,474	-	6,474													6,474
101	Operating Leases - Current	9,280	445	9,725									(9,725)			-	-
102	Fermi 2 Outage Accrual	11,993	-	11,993													11,993
103	Other Current Liabilities	182,318	876	183,194	-	-	-	-	-	-	-	(289)	(100)	-	-	(14,154)	168,651
104	TOTAL CURRENT LIABILITIES	1,366,674	2,777	1,369,451	-	-	-	-	(16,767)	20,780	(22,382)	(10,014)	19,039	-	(1,161)	(244,904)	1,114,042
105	DEFERRED CREDITS																
106	Regulatory Liab-Renewable Energy Program	20,780	-	20,780						(20,780)							-
107	Regulatory Liab-Energy Optimization	34,217	-	34,217					(34,217)								-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	117,355	-	117,355													117,355
109	Regulatory Liab-OPEB Capitalized	63,042	-	63,042													63,042
110	Regulatory Liab- Pension Capitalized	-	-	-													-
111	Regulatory Liab- Negative Pension	-	-	-													-
112	Fermi 2 Decommissioning	294,800	-	294,800									(294,800)				-
113	Accumulated Deferred Income Taxes	3,830,861	3,170	3,834,032	(908,102)	-	-		(14,519)	(3,301)	-		7,508			(62,445)	2,853,174
114	Accumulated Deferred Investment Tax Credit	170,998	-	170,998	(100,837)					(37,324)						-	32,836
115	Tax Reform Reg Liab-Refundable Income Taxes	1,622,612	3,752	1,626,364					(2,809)	(77,369)	-		-			-	1,546,186
116	Other Deferred Credits	31,937	887	32,824	-	-	-	-	-	-	-	(4,110)	-	-	-	(1,765)	26,949
117	TOTAL DEFERRED CREDITS	6,186,603	7,809	6,194,412	(1,008,939)	-	-	-	(51,545)	(138,775)	-	(4,110)	(287,292)	-	-	(64,210)	4,639,541
118	TOTAL LIABILITIES AND OTHER CREDITS	30,050,819	11,665	30,062,483	(1,008,939)	(199,686)	(105,753)	(66,872)	(107,097)	(2,439,013)	(22,382)	(59,373)	(3,336,145)	(712,311)	(1,161)	(404,422)	21,599,330
119	TOTAL ASSETS - TOTAL LIABILITIES	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	(0)

1/ Deferred Tax & ITC adjustment sponsored by Witness Wisniewski

Michigan Public Service Commission
DTE Electric Company
Asset Retirement Obligation (ASC 410) &
Nuclear Decommissioning Trust Fund
Balance Sheet Elimination
(\$000)

Case No.: U-21534
 Exhibit: A-2
 Schedule: B7
 Witness: T. M. Uzenski
 Page: 1 of 2

For the Period Ended December 31, 2022

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	Nuclear Decomm. Trust Fund	Fermi 2 ARO	Subtotal Fermi 2	Fermi 1 ARO & Funding	Non-Nuclear ARO	Grand Total
				(b) + (c)			(d)+(e)+(f)
1	Asset Retirement Cost (ARC) Plant	-	228,094	228,094	-	496,275	724,369
2	Accumulated Depreciation	-	(191,970)	(191,970)	-	137,479	(54,491)
3	Net ARC Plant	-	36,124	36,124	-	633,754	669,878
4	Special Fund	-	-	-	2,857	-	2,857
5	Nuclear Decommissioning Trust Fund	1,821,744	-	1,821,744	-	-	1,821,744
6	Regulatory Asset	1,008,326	(36,124)	972,202	-	-	972,202
7	Total Assets	<u>2,830,070</u>	<u>-</u>	<u>2,830,070</u>	<u>2,857</u>	<u>633,754</u>	<u>3,466,681</u>
8	Retained Earnings (Loss)	-	-	-	(19,120)	-	(19,120)
9	Other Comprehensive Income (Loss)	-	-	-	-	-	-
10	Short Term Debt	5,582	-	5,582	-	(15,211)	(9,629)
11	ARO Liability, Non-Current	-	2,542,349	2,542,349	29,599	648,965	3,220,912
12	ARO Liability, Current	-	-	-	100	-	100
13	Deferred Credits	2,824,488	(2,542,349)	282,140	-	-	282,140
14	Deferred Taxes	-	-	-	(7,722)	-	(7,722)
15	Tax Reform Regulatory Liability	-	-	-	-	-	-
16	Total Liabilities & Capitalization	<u>2,830,070</u>	<u>-</u>	<u>2,830,070</u>	<u>2,857</u>	<u>633,754</u>	<u>3,466,681</u>

Source: Company Books & Records

**Michigan Public Service Commission
DTE Electric Company
Asset Retirement Obligation (ASC 410) &
Nuclear Decommissioning Trust Fund
Balance Sheet Elimination
(\$000)**

Case No.: U-21534
Exhibit: A-2
Schedule: B7
Witness: T. M. Uzenski
Page: 2 of 2

13 Month Average Period Ended December 31, 2022

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	Nuclear Decomm. Trust Fund	Fermi 2 ARO	Subtotal Fermi 2	Fermi 1 ARO & Funding	Non-Nuclear ARO	Grand Total
				(b) + (c)			(d)+(e)+(f)
1	Asset Retirement Cost (ARC) Plant	-	228,094	228,094	-	468,581	696,675
2	Accumulated Depreciation	-	(191,185)	(191,185)	-	96,738	(94,447)
3	Net ARC Plant	-	36,909	36,909	-	565,319	602,228
4	Special Fund	-	-	-	2,864	-	2,864
5	Nuclear Decommissioning Trust Fund	1,902,812	-	1,902,812	-	-	1,902,812
6	Regulatory Asset	865,150	(36,909)	828,241	-	-	828,241
7	Total Assets	<u>2,767,962</u>	<u>-</u>	<u>2,767,962</u>	<u>2,864</u>	<u>565,319</u>	<u>3,336,145</u>
8	Retained Earnings (Loss)	-	-	-	(18,530)	-	(18,530)
9	Other Comprehensive Income (Loss)	-	-	-	-	-	-
10	Short Term Debt	(3,872)	-	(3,872)	(56)	(15,211)	(19,139)
11	ARO Liability, Non-Current	-	2,477,034	2,477,034	28,858	580,530	3,086,422
12	ARO Liability, Current	-	-	-	100	-	100
13	Deferred Credits	2,771,834	(2,477,034)	294,800	-	-	294,800
14	Deferred Taxes	-	-	-	(7,508)	-	(7,508)
15	Tax Reform Regulatory Liability	-	-	-	-	-	-
16	Total Liabilities & Capitalization	<u>2,767,962</u>	<u>-</u>	<u>2,767,962</u>	<u>2,864</u>	<u>565,319</u>	<u>3,336,145</u>

Source: Company Books & Records

Michigan Public Service Commission
DTE Electric Company
Historical Adjusted Net Operating Income
For the 12 Months Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C1
 Witness: T. M. Uzenski
 Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Source	Recorded Amount	Rate Case Adjustments & Normalizations 1/	Adjusted Total
					<i>Col. (c) + Col. (d)</i>
1	Operating Revenues	Exh. A-3, Sch. C3	6,362,291	(1,185,320)	5,176,971
2	<u>Operating Expenses</u>				
3	Fuel and Purchased Power	Exh. A-3, Sch. C4	1,991,724	(595,946)	1,395,778
4	Operations and Maintenance Expenses	Exh. A-3, Sch. C5	1,528,527	(304,088)	1,224,439
5	Depreciation and Amortization	Exh. A-3, Sch. C6	1,160,956	(104,801)	1,056,155
6	Property Taxes	Exh. A-3, Sch. C7	286,558	(20,659)	265,899
7	Other Taxes	Exh. A-3, Sch. C7	49,869	(694)	49,175
8	State & Local Income Taxes	Exh. A-3, Sch. C9	72,939	(6,173)	66,766
9	Federal Income Taxes	Exh. A-3, Sch. C8	(38,450)	65,786	27,336
10	Other Utility (Income)/Deductions	Exh. A-3, Sch. C1.1	-	(6,400)	(6,400)
11	Total Operating Expenses		5,052,123	(972,974)	4,079,149
12	Operating Income (Line 1 less Line 11)	P-521 page 114, line 26	1,310,168	(212,346)	1,097,822
13	<u>Operating Income Adjustments</u>				
14	Allowance for Funds Used During Construction	Exh. A-3, Sch. C11	-	37,473	37,473
15	Loss on Reaquired Securities	Workpaper TMU-10	-	(3,310)	(3,310)
16	Total Operating Income Adjustments		-	34,163	34,163
17	Adjusted Net Operating Income		1,310,168	(178,183)	1,131,985

1/ Rate Case Adjustments and Normalization per Exhibit A-3, Schedule C1.1, Lines 20, 36 and 42

Michigan Public Service Commission
DTE Electric Company
Adjustments to Historical Net Operating Income
For the 12 Months Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C1.1
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description	Source Exhibit	Revenues	Fuel & Purch Pwr	O&M	Deprec and Amort	Property Taxes	Other Taxes	State & Local Income Taxes	Federal Income Taxes	AFUDC	Other Inc./Ded.	Adjusted NOI
For the Year Ended December 31, 2022													
1	Net Operating Income Unadjusted	WP TMU-3	6,362,291	1,991,724	1,528,527	1,160,956	286,558	49,869	72,939	(38,450)	-	-	1,310,168
2	<u>Rate Case Adjustments to Net Operating Income</u>												
3	Reclass Fuel Handling Expense	A-13 C5.1		(30,979)	30,979								-
4	Interest and Dividend Income	P-521 p.117 (line 37)										8,525	8,525 1/
5	Excluded Corporate Memberships	A-3 C14			(354)				22	70			262
6	Excluded Advertising Expenses	A-3 C15			(5,714)				355	1,125			4,234
7	MERC Net Operating Income Adjustment	A-3 C16	-	-	(5,577)	3,952	975	169	1	(15)			494
8	Power Supply Cost Recovery (PSCR) Offsets	A-3 C17	(547,330)	(547,330)									-
9	Eliminate Nuclear Surcharge Program	A-3 C18	(38,099)		(28,555)	(8,769)	-		(48)	(153)			(574)
10	Eliminate Top Five Executive Incentive Compensation	A-3 C19		-	(10,157)	-	-		631	2,000	-	-	7,526
11	Eliminate MGM Rent	WP TMU-4			(963)				60	190			713
12	Reclassify Customer Deposit Interest	WP TMU-5										(1,729)	(1,729) 1/
13	Eliminate Transitional Reconciliation Mechanism (TRM)	WP TMU-6	(1,726)	-	(14,767)	13,025	-	(11)	2	5			20
14	Eliminate Energy Waste Reduction Program	WP TMU-7	(233,193)		(174,387)	(20,626)		(301)	(2,352)	(7,460)			(28,066)
15	Eliminate Renewable Energy Program	WP TMU-8	(268,613)	(7,941)	(51,672)	(92,383)	(21,634)	(551)	(5,864)	66,785			(155,353)
16	Eliminate Low Income Energy Assistance Fund (LIEAF)	WP TMU-9	(23,895)		(23,895)				-	-			-
17	Relcass to Other Deductions - below the line	A-13 C5.10			(299)				19	59			222
18	Regional Relations Expenses Political Advocacy	A-13 C5.10			(314)				19	62			233
19	EIS Loss											(396)	(396)
20	Subtotal Rate Case Adjustments to NOI		(1,112,857)	(586,251)	(285,675)	(104,801)	(20,659)	(694)	(7,155)	62,668	-	6,400	(163,890)
21	Historical Year - Rate Case Adjusted	L1+L20	5,249,434	1,405,473	1,242,852	1,056,155	265,899	49,175	65,784	24,218	-	6,400	1,146,278
22	<u>Normalization Adjustments</u>												
23	Employee Incentive Plan Normalization Adjustment	A-3 C20			(4,787)				297	943			3,547
24	Weather Normalization Adjustment	A-3 C21	(42,463)	(9,695)					(2,035)	(6,454)			(24,279)
25	Open								-	-			-
26	Open	A-13 C5.3			(0)				0	0			0
27	Other Power Gen Normalization Adj.	A-13 C5.5			-				-	-			-
28	Distribution Normalization Adj.	A-13 C5.6			(2,864)				178	564			2,122
29	Open	A-13 C5.7			-				-	-			-
30	One time consulting costs	A-13 C5.10			(8,020)				498	1,580			5,942
31	Injuries & Damages - 5 year average	A-13 C5.10			1,282				(80)	(253)			(950)
32	Environmental Remediation - 5 year average	A-13 C5.10			(11)				1	2			8
33	Benefits Normalizations	A-13 C5.11			(4,869)				302	959			3,608
34	Incentive Compensation deferral above base amount	A-13 C5.10			856				(53)	(169)			(634)
35	COVID-19 Voluntary Refund (Case U-20921)	1X Adj (Acct 449.1)	(30,000)						(1,863)	(5,909)			(22,228)
36	Subtotal Normalization Adjustments		(72,463)	(9,695)	(18,413)	-	-	-	(2,755)	(8,736)	-	-	(32,864)
37	Subtotal Historical Net Operating Income	L21+L36	5,176,971	1,395,778	1,224,439	1,056,155	265,899	49,175	63,029	15,482	-	6,400	1,113,414
38	Allowance for Funds Used During Construction (AFUDC)	A-3 C11									37,473		37,473 1/
39	Amortization of the Loss on Reacquired Debt	WP TMU-10										(3,310)	(3,310) 1/
40	Income Tax Effect of Interest	A-3 C12							3,777	11,979			(15,755)
41	Interest Synchronization Tax Adjustment	A-3 C13							(39)	(124)			164
42	Subtotal Operating Income Adjustments		-	-	-	-	-	-	3,738	11,854	37,473	(3,310)	18,571
43	Adjusted Historical Net Operating Income	L37+L42	5,176,971	1,395,778	1,224,439	1,056,155	265,899	49,175	66,766	27,336	37,473	3,090	1,131,985

1/ These items are displayed gross of tax since they are already included in the calculation of utility income tax expense.

**Michigan Public Service Commission
DTE Electric Company
Historical Revenue Conversion Factor
For the Period Ended December 31, 2022**

Case No.: U-21534
Exhibit: A-3
Schedule: C2
Witness: K. M. Vangilder
Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Calculations	Amount
1	Income Before Income Taxes		100.00
2	Michigan Income Tax Rate	(1)	5.88%
3	Composite Municipal Income Tax Rate		0.33%
4	Total State and Local Tax Rates	L2 + L3	6.21%
5	Federal Income Tax Base	L1 - (L4x100)	93.79
6	Federal Income Tax Rate		21.00%
7	Federal Income Tax	L5 x L6	19.70
8	Income after Federal, Michigan and Municipal Taxes	L5 - L7	74.09
9	Revenue Conversion Factor	L1 ÷ L8	1.3496

(1) 6% Statutory rate at 98.00% apportionment as supported by Witness Wisniewski

**Michigan Public Service Commission
DTE Electric Company
Historical Operating Revenue
For the Period Ended December 31, 2022
(\$000)**

Case No.: U-21534
Exhibit: A-3
Schedule: C3
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Source	Sales Revenue
1	Sales Revenue	P-521 Pg 300, Line 10	5,552,038
2	Sales for Resale	P-521 Pg 300, Line 11	286,833
3	Provision for Rate Refunds	P-521 Pg 300, Line 13	323,122
4	Miscellaneous Revenues	P-521 Pg 300, Line 26	<u>200,297</u>
5	Total Electric Operating Revenues		<u><u>6,362,291</u></u>

Michigan Public Service Commission
DTE Electric Company
Historical Fuel and Purchased Power
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C4
 Witness: T. M. Uzenski
 Page: 1 of 1

Line No.	(a) Description	(b)	(c)
		FERC/ MPSC Account	Fuel and Purchased Power (\$000)
1	Power Supply Related Expenses		
2	Fuel - Steam	501	882,402
3	Allowances	509	3,184
4	Fuel - Nuclear	518	42,451
5	Fuel - Other	547	88,666
6	Purchased Power	555	798,041
7	Other Power Supply	557	(226,308)
8	Load Dispatching	561	12,641
9	Transmission of Electricity by Others	565	381,964
10	Regional Market Expenses	575	8,682
11	Total Power Supply Related Expenses		<u>1,991,724</u>

Michigan Public Service Commission
DTE Electric Company
Historical Operation and Maintenance Expenses
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C5
 Witness: T. M. Uzenski
 Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Operation and Maintenance Expenses (\$000)
1	<u>Operation & Maintenance Expenses</u>		
2	Operations Expenses (401)	P-521 Pg. 114 , Line 4	3,003,017
3	Maintenance Expenses (402)	P-521 Pg. 114, Line 5	517,233
4	Operations and Maintenance Expenses	P-521 Pg. 323, Line 198	3,520,250
5	Less: Fuel & PP		(1,991,724)
6	Base Operation & Maintenance Expenses		<u>1,528,527</u>

Michigan Public Service Commission
DTE Electric Company
Historical Depreciation and Amortization Expenses
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C6
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Depreciation and Amortization Expense (\$000)
1	<u>Depreciation and Amortization Expenses</u>		
2	Depreciation Expenses (403, 403.1)	P-521 page 114, lines 6 & 7	1,001,220
3	Amort. & Dep. Of Utility Plant (404-405)	P-521 page 114, line 8	145,953
4	Amort. Of Utility Plant Acq. Adj. (406)	P-521 page 114, line 9	6,624
5	Regulatory Debits (407.3)	P-521 page 114, line 12	7,592
6	Regulatory Credits (407.4)	P-521 page 114, line 13	(170,436)
7	Accretion Expense (411.10)	P-521 page 114, line 24	170,002
8	Total Depreciation and Amortization Expense	Sum Lines 2 thru 7	<u>1,160,956</u>

Michigan Public Service Commission
DTE Electric Company
Historical General Taxes
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C7
Witness: S. L. Wisniewski
Page: 1 of 1

(a)		(b)	(c)
Line No.	Description	Source	General Taxes (\$000)
1	Property Taxes	P-521 page 263, col. (I), L10	286,558
2	Payroll Taxes	P-521 page 263, col. (I), L14 + L42	36,678
3	MPSC Fee	P-521 page 263, col. (I), L52	12,948
4	Use Tax	P-521 page 263, col. (I), L16	28
5	Other	P-521 page 263, col. (I), L8	216
6	Total Other General Taxes		49,869
7	Total Historical General Taxes		336,427

Michigan Public Service Commission
DTE Electric Company
Historical Federal Income Taxes
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C8
 Witness: S. L. Wisniewski
 Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Federal Income Taxes (\$000)
1	Income Taxes - Federal (Current)	P-521 page 114, col. (c), L15	(0)
2	Income Taxes - Federal (Deferred)	See Part III, Section 7a	(38,450)
3	Total Historical Federal Income Taxes		(38,450)

**Michigan Public Service Commission
DTE Electric Company
Historical State and Local Income Taxes
For the Period Ended December 31, 2022
(\$000)**

Case No.: U-21534
Exhibit: A-3
Schedule: C9
Witness: S. L. Wisniewski
Page: 1 of 1

(a)		(b)	(c)
Line No.	Description	Source	State & Local Income Taxes (\$000)
1	Income Taxes - State & Local (Current)	P-521 page 114, col. (c), L16	(0)
2	Income Taxes - State & Local (Deferred)	See Part III, Section 7a	72,939
3	Total Historical State & Local Taxes		72,939

**Michigan Public Service Commission
DTE Electric Company
Historical Other Taxes
For the Period Ended December 31, 2022
(\$000)**

Case No.: U-21534
Exhibit: A-3
Schedule: C10
Witness: S. L. Wisniewski
Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Source	Other (or Local) Taxes (\$000)

Local income taxes are included with State income tax on Exhibit A-3,C9

Michigan Public Service Commission
DTE Electric Company
Historical Allowance for Funds Used During Construction
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C11
 Witness: T. M. Uzenski
 Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Source	AFUDC (\$000)
1	<u>Allowance for Funds Used During Construction</u>		
2	AFUDC - Equity (419.1)	P-521 page 117, Line 38	26,247
3	AFUDC - Debt (432)	P-521 page 117, Line 69	11,225
4	Total AFUDC per Income Statement		37,473
5	Less: AFUDC attributed to TRM Program	Workpaper TMU-6	-
6	Allowance for Funds Used During Construction		<u>37,473</u>

Michigan Public Service Commission
DTE Electric Company
Historical Tax Effect of Interest Allowed in Ratemaking Formula
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C12
Witness: K. M. Vangilder
Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exh. A-2, Sch. B1	\$ 20,116,777
2	Weighted Cost of Debt (1)	Exh. A-4, Sch. D1	<u>1.53%</u>
3	Interest Allowed in Ratemaking Formula	Line 1 x Line 2	\$ 307,465
4	Interest Deduction included in Recorded Income Tax Accruals	WP-KMV-1	<u>368,282</u>
5	Increase / (Decrease) in Interest Deduction	Line 3 - Line 4	\$ (60,817)
6	Composite State and Municipal Income Tax Rate	Exh. A-3, Sch. C2	<u>6.21%</u>
7	Effect on State and Municipal Income Tax Expense	(Line 5 x Line 6) x -1	\$ <u>3,777</u>
8	Effect on Federal Taxable Income	(Line 5 + Line 7) x -1	\$ 57,041
9	Federal Income Tax Rate	Exh. A-3, Sch. C2	<u>21.00%</u>
10	Effect on Federal Income Tax Expense	Line 8 x Line 9	\$ <u>11,979</u>
11	Total Tax Effect on Net Operating Income	(Line 7 + Line 10) x -1	\$ <u>(15,755)</u>

(1) Includes Short and Long-Term Interest Rates

Michigan Public Service Commission
DTE Electric Company
Historical Tax Effect of Interest Synchronization Adjustment
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C13
Witness: K. M. Vangilder
Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exh. A-2, Sch. B1	\$ 20,116,777
2	JDITC Debt Portion of Capital Structure	Exh. A-4, Sch. D1	<u>0.08%</u>
3	Debt Portion of Rate Base Funded by JDITC	Line 1 x Line 2	\$ 16,763
4	Cost of Long-Term Debt	Exh. A-4, Sch. D1	<u>3.77%</u>
5	Imputed Interest	Line 3 x Line 4	\$ 632
6	Composite State and Municipal Income Tax Rate	Exh. A-3, Sch. C2	<u>6.21%</u>
7	Effect on State and Municipal Income Tax Expense	(Line 5 x Line 6) x -1	\$ <u>(39)</u>
8	Effect on Federal Taxable Income	(Line 5 + Line 7) x -1	\$ (593)
9	Federal Income Tax Rate	Exh. A-3, Sch. C2	<u>21.00%</u>
10	Effect on Federal Income Taxes	Line 8 x Line 9	\$ <u>(124)</u>
11	Synchronization Tax Adjustment to NOI	(Line 7 + Line 10) x -1	\$ <u><u>164</u></u>

Michigan Public Service Commission
DTE Electric Company
Historical Corporate Memberships Adjustment
For the Period Ended December 31, 2022
(\$000)

Case No: U-21534
Exhibit: A-3
Schedule: C14
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b) Amount	(c) Reference
1	Memberships Charged to Operating Expense		
2	AUTOMATION ALLEY	18	
3	BOARDVANTAGE INC	30	
4	CENTER FOR WORKPLACE COMPLIANCE	10	
5	DETROIT REGION AEROTROPOLIS	10	
6	HR POLICY ASSOCIATION	14	
7	MICHIGAN STATE UNIVERSITY	17	
8	MONEY MEDIA INC	51	
9	RELEAF MICHIGAN INC	1	
10	THE UNIVERSITY OF TEXAS AT AUSTIN	35	
11	WILDLIFE HABITAT COUNCIL INC	15	
12	OTHER AREA CHAMBER OF COMMERCE	55	
13	Subtotal Miscellaneous Corporate	255	Account 930.2 (Exh. A-13 C5.10)
14	EDISON ELECTRIC INSTITUTE	78	Account 506 & 921
15	NUCLEAR ENERGY INSTITUTE INC	21	Account 524
16	Subtotal Other	99	
17	Total Excluded Memberships	354	
18	Less: Composite Municipal		
19	and State Income Tax @ 6.21%	22	
20		332	
21	Less: Federal Income Tax @ 21.00%	70	
22			
23	Net Excluded Expense	262	

Source: Company Books and Records

**Michigan Public Service Commission
DTE Electric Company
Historical Advertising Adjustment
For the Period Ended December 31, 2022
(\$000)**

Case No.: U-21534
Exhibit: A-3
Schedule: C15
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b) Amount
1	Related to Public Health and Safety	1,960
2	Related to Conservation of Energy & Environmental Protection	3,524
3	Related to Billing Practices, Rates and Other Communications Beneficial to Customers	196
4	Other Advertising Programs	<u>5,714</u>
5	Total Advertising Programs	11,394
6	Less: Allowable Items (Lines 1 through 3)	<u>5,680</u>
7	Gross Excluded Expense	5,714
8	Less: Composite Municipal and State Income Tax @ 6.21%	<u>355</u>
9		5,359
10	Less: Federal Income Tax @ 21.00%	<u>1,125</u>
11	Net Excluded Expense	<u>4,234</u>

Source: Company Books and Records

Michigan Public Service Commission
DTE Electric Company
Historical MERC Net Operating Income
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C16
Witness: T. M. Uzenski
Page: 1 of 2

Line No.	(a) Description	(b) MERC Contribution	(c) Credit to PSCR Fuel Clause (1)	(d) Fuel Handling Charge to Base Rates (2)
1	REVENUES			
2	Third Party Dock Services	5,257 (1)	5,257	-
3	Net Coal & Transportation Sales	649 (1)	649	-
4	TOTAL OPERATING REVENUE	5,906	5,906	-
5	Equity Earnings of Venture Fuels	110 (1)	110	-
6	TOTAL REVENUE	6,016	6,016	-
7	EXPENSES			
8	Site Operating Expenses	13,110 (1)	13,110	-
9	Non-Site Operating Expenses:			
10	O&M	3,850 (2)		3,850
11	Depreciation	3,952 (2)		3,952
12	Property Taxes	975 (2)		975
13	Payroll Taxes	169 (2)		169
14	Income Taxes, State	1 (2)		1
15	Income Taxes, Federal	(15) (2)	-	(15)
16	TOTAL EXPENSES	22,043	13,110	8,933
17	Net Operating Income/(Expense)	(16,026)	(7,094)	(8,933)
18	INTEREST CHARGES			
19	Interest on Long Term Debt	- (2)	-	-
20	Amortization of Debt Discount & Expense	- (2)	-	-
21	Amortization of Loss on Reacquired Debt	- (2)	-	-
22	Other Interest	494 (2)	-	494
23	Total Interest Charges	494	-	494
24	NET CONTRIBUTION	(16,521)	(7,094)	(9,427)

MERC Contribution from col. (b) = (c) + (d)

Notes:

- MERC contribution per col. (b) flows through to customers through PSCR col. (c) or Base Rates col. (d)
- (1) PSCR credit equals the net benefit of Third Party Dock Services, Net Coal & Transportation Sales, Equity Earnings of Venture Fuels less Site Operating Expenses
- (2) Fuel Handling expense in base rates equals all Non-Site Operating Expenses (Administrative, Depreciation, Property Taxes, Income Taxes & Interest Charges).

Michigan Public Service Commission
DTE Electric Company
Historical MERC Net Operating Income Adjustment
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C16
Witness: T. M. Uzenski
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)
			Reclassification of Fuel Handling			
Line No.	Description	DTE Electric MPSC P-521 Format (1)	MERC Fuel Handling in P-521 (2)	MERC Fuel Handling Line Item Reclassification (3)	Subtotal MERC NOI Adjustment (4)	Total DTE Electric with MERC NOI Adjustment
					(c) + (d)	(b) + (e)
	<u>Income Statement</u>					
1	Revenue	6,362,291	-	-	-	6,362,291
2	Fuel & Purchased Power	1,960,745	-	-	-	1,960,745
3	Operation and Maintenance	1,559,506	(9,427)	3,850	(5,577)	1,553,929
4	Depreciation & Amortization	1,160,956	-	3,952	3,952	1,164,908
5	Property Tax	286,558	-	975	975	287,533
6	Other Tax	49,869	-	169	169	50,038
7	State & Local Income Tax	72,939	-	1	1	72,940
8	Federal Income Tax	(38,450)	-	(15)	(15)	(38,465)
9	Other	-	-	-	-	-
10	Total Utility Operating Expenses	5,052,123	(9,427)	8,933	(494)	5,051,629
11	Net Operating Income/(Expense)	1,310,168	9,427	(8,933)	494	1,310,662
12	Other (Income)/Deductions	(15,505)	-	-	-	(15,505)
13	Net Interest Charges	364,141	-	494	494	364,635
14	Net Income	961,532	9,427	(9,427)	0	961,532

(1) Carried from Exhibit A-3 C1.1, line 1 (per P-521) + line 3 (reclass Fuel Handling to O&M)

(2) The fuel handling charge from MERC is included in account 501 in DTEE's P-521.

(3) MERC fuel handling is reallocated to the proper line item classification for ratemaking purposes (amounts are carried from page 1, column (d) of this exhibit).

(4) MERC NOI adjustment carried to Exhibit A-3, C1.1 reflects an increase in Net Operating Income equal to MERC's interest but has zero net income impact.

Michigan Public Service Commission
DTE Electric Company
Historical Power Supply Cost Recovery Items
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C17
 Witness: T. M. Uzenski
 Page: 1 of 1

	(a)	(b)	(c)	(d)
Line No.	Description	Account No.	Amount	Reference
1	REVENUES			
2	PSCR Factor Revenue	440-448	266,907	
3	PSCR VGP Transfer Credits	456	(67,323)	
4	PSCR (Over)/Under Recovery	449.1	273,862	
5	Renewable Transfer Revenue	449.1	(226,308)	
6	PSCR Factor Revenue Elimination		247,138	
7	Interconnection Revenues	447	286,833	
8	System Integrity Penalty Revenue	456	-	
9	Ancillary Transmission Revenue	456.1	9,326	
10	Reclassify Revenues netted in PSCR Cost		296,159	
11	Eliminate Cost of Steam (1)	456	4,033	
12	Total Revenue Adjustment		547,330	Sum Lines 6,10,11
13	FUEL & PURCHASED POWER			
14	Eliminate PSCR Factor Revenue		247,138	Line 6
15	Reclassify Revenues (netted in PSCR Cost)		296,159	Line 10
16	Eliminate Cost of Steam (1)		4,033	Line 11
17	Total Fuel & Purchased Power Adjustment		547,330	
18	Net Operating Income Impact		-	Line 12 - Line 17

Source: Company Books and Records

(1) Steam expense, net of steam revenue, is excluded from base rates and PSCR

Michigan Public Service Commission
DTE Electric Company
Eliminate Nuclear Surcharge
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
 Exhibit: A-3
 Schedule: C18
 Witness: T. M. Uzenski
 Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Account	Amount
1	Nuclear Surcharge	440, 442, 444	38,099
2	<u>Operating Expenses</u>		
3	Site Security & Radiation Protection (O&M)	517-532	28,555
4	Nuclear Funding (DD&A Reg Credits)	407.4	8,769
5	Operating Expense		37,324
6	Net Operating Income		775
7	Less: Composite Municipal and State Income Tax @ 6.21%		48
8	Less: Federal Income Tax @ 21%		153
9	Subtotal Income Tax		201
10	Net Operating Income		574

Source: Company Books & Records

Michigan Public Service Commission
DTE Electric Company
Historical Executive Incentive Compensation Adjustment
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C19
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Amount	Reference
1	Top 5 Executives' Incentive Compensation	10,157	1/, 2/
2	Less: Composite Municipal and State Income Tax @ 6.21%	<u>631</u>	
3		9,526	
4	Less: Federal Income Tax @ 21%	<u>2,000</u>	
5	Net Operating Income Adjustment	<u><u>7,526</u></u>	

1/ Per Company Book and Records

2/ Sponsored by Witness Cooper

Michigan Public Service Commission
DTE Electric Company
Historical Employee Incentive Plan Normalization Adjustment
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C20
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Amount	Reference
1	Employee Incentive Plan Expense	80,402	1/, 2/
2	Less Top 5 Elimination	<u>(10,157)</u>	Exh. A-3 C19
3	Employee Incentive Plan Expense excl. Top 5	70,245	
4	Normalized Incentive Plan Accrual	<u>65,458</u>	1/, 2/
5	Normalization Adjustments	4,787	3/
6	Less: Composite Municipal and State Income Tax @ 6.21%	<u>297</u>	
7		4,490	
8	Less: Federal Income Tax @ 21%	<u>943</u>	
9	Net Operating Income Adjustment	<u><u>3,547</u></u>	

1/ Per Company Book and Records

2/ Sponsored by Witness Cooper

3/ Normalizes long-term incentives to 100% of plan target (\$4.1M) and short-term incentives to 100% of plan target (\$1.4M) offset by prior year adjustments \$0.6M.

Michigan Public Service Commission
DTE Electric Company
Historical Weather Normalization Adjustment
For the Period Ended December 31, 2022
(\$000)

Case No.: U-21534
Exhibit: A-3
Schedule: C21
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)
Line No.	Customer Class	(Colder)/ Warmer Sales (GWh)	Sales Revenue	PSCR Expense	Sales Margin Impact
1	Residential	198	33,093	6,651	26,442
2	Commercial Secondary	52	6,202	1,742	4,460
3	Commercial Primary	32	2,502	1,061	1,441
4	Industrial	7	463	241	222
5	Choice	14	203	-	203
6	Total	<u>302</u>	<u>42,463</u>	<u>9,695</u>	<u>32,768</u>
7					
8	Less: Composite Municipal and State Income Tax @ 6.21%				<u>2,035</u>
9					30,733
10	Less: Federal Income Tax @ 21%				<u>6,454</u>
11	Net Operating Income Adjustment				<u>24,279</u>

Source: Company Books and Records

Michigan Public Service Commission
DTE Electric Company
Historical Rate of Return Summary
For the 13-Month Average Period Ended 12/31/2022

Case No.: U-21534
Exhibit: A-4
Schedule: D1
Witness: K. M. Vangilder
Page: 1 of 1

Line No.	(a) Description	(b) Capital Structure			(e) Cost Rate %	(g) Weighted Costs			
		(b) Amount (\$000)	(c) Percent Permanent Capital (1), (7)	(d) Percent of Total Capital		(f) Permanent Capital	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return
1	Long-Term Debt, net	8,034,286 (2)	51.05%	39.94%	3.77% (3)	1.92%	1.51%	1.0000	1.51%
2	Preferred Stock	0	0.00%	0.00%	0.00% (4)	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	7,703,775 (2)	48.95%	38.30%	9.90% (5)	4.85%	3.79%	1.3496	5.12%
4	Total	15,738,061	100.00%			6.77%			
5	Short-Term Debt	167,142 (2)		0.83%	2.75% (6)		0.02%	1.0000	0.02%
6	Investment Tax Credit (ITC) - Debt	16,763		0.08%	3.77%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	16,073		0.08%	9.90%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	32,836 (2)							
9	Deferred Income Taxes (Net)	4,178,738 (2)		20.77%	0.00%		0.00%		0.00%
10	Total	20,116,777		100.00%			5.33%		6.66%
11	Rate Base per Exh. A-2, Sch. B1	20,116,777							

(1) Excludes Short-Term Debt, Deferred Investment Tax Credit, and Deferred Income Taxes to calculate the rate of return for Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation section 1.46-6

(2) See Exh. A-2, Sch. B5, Cols. (e) thru (i), Line 119

(3) See Exh. A-4, Sch. D2

(4) See Exh. A-4, Sch. D4

(5) See Exh. A-4, Sch. D5

(6) See Exh. A-4, Sch. D3

(7) Permanent Capital Structure at Year End 12/31/2022 (per Exh. A-2, Sch. B5.1):

Long-Term Debt, net	7,832,594	49.1%
Common Shareholders' Equity	8,133,345	50.9%
Total	15,965,939	100.0%

Michigan Public Service Commission
DTE Electric Company
Historical Cost of Long-Term Debt
as of December 31, 2022

Case No.: U-21534
Exhibit: A-4
Schedule: D2
Witness: T. J. Lepczyk
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Issue Name	Original Issue Date	Stated Maturity	Interest Rate %	Amount of Offering (\$000)	Price to Public %	Expenses of Financing %	Net Proceeds to the Company %	Cost Based on Net Proceeds %	12/31/2022 Amount Outstanding (\$000)	Annual Cost (\$000)
1	2002 Series B	10/23/02	10/15/32	6.350%	225,000	99.33%	1.0%	98.37%	6.47%	225,000	14,566
2	2005 Series BR	02/07/05	02/15/35	5.450%	200,000	99.59%	1.0%	98.56%	5.55%	200,000	11,098
3	2005 Series C	09/29/05	10/01/23	5.190%	100,000	100.00%	0.5%	99.51%	5.23%	100,000	5,232
4	2005 Series E	10/06/05	10/01/37	5.700%	250,000	99.40%	1.0%	98.42%	5.81%	250,000	14,523
5	2006 Series A	06/01/06	06/01/36	6.625%	250,000	99.95%	1.0%	98.95%	6.71%	250,000	16,766
6	2007 Series A	12/18/07	03/15/38	6.470%	50,000	100.00%	0.8%	99.17%	6.53%	50,000	3,266
7	2011 Series D	09/01/11	09/01/23	4.310%	102,000	100.00%	0.6%	99.41%	4.37%	102,000	4,461
8	2011 Series E	09/01/11	09/01/26	4.460%	77,000	100.00%	0.6%	99.41%	4.51%	77,000	3,476
9	2011 Series F	09/01/11	09/01/41	5.670%	46,000	100.00%	0.6%	99.41%	5.71%	46,000	2,627
10	2011 Series H	09/20/11	09/01/41	4.500%	140,000	98.87%	1.1%	97.81%	4.64%	140,000	6,490
11	2012 Series B	06/22/12	06/15/42	3.950%	250,000	99.57%	1.0%	98.54%	4.03%	250,000	10,086
12	2013 Series A	03/27/13	04/01/43	4.000%	375,000	99.55%	1.0%	98.50%	4.09%	375,000	15,327
13	2013 Series B	08/27/13	03/15/24	3.650%	400,000	99.59%	0.8%	98.80%	3.79%	400,000	15,156
14	2014 Series A	06/04/14	06/01/26	3.770%	100,000	100.00%	0.6%	99.39%	3.83%	100,000	3,834
15	2014 Series B	06/04/14	06/01/44	4.600%	150,000	100.00%	0.6%	99.39%	4.64%	150,000	6,957
16	2014 Series D	07/02/14	03/01/25	3.375%	350,000	99.86%	0.8%	99.07%	3.48%	350,000	12,180
17	2014 Series E	07/02/14	07/01/44	4.300%	350,000	99.85%	1.0%	98.83%	4.37%	350,000	15,296
18	2015 Series A	03/11/15	03/15/45	3.700%	500,000	99.77%	1.0%	98.73%	3.77%	500,000	18,854
19	2016 Series A	05/17/16	06/01/46	3.700%	300,000	99.93%	1.1%	98.82%	3.77%	300,000	11,297
20	2017 Series B	08/09/17	08/15/47	3.750%	440,000	99.95%	1.1%	98.85%	3.81%	440,000	16,784
21	2018 Series A	05/07/18	05/15/48	4.050%	525,000	99.55%	1.1%	98.46%	4.14%	525,000	21,736
22	2019 Series A	02/15/19	03/01/49	3.950%	650,000	99.20%	1.1%	98.11%	4.06%	650,000	26,385
23	2020 Series A	02/26/20	03/01/30	2.250%	600,000	99.88%	0.8%	99.04%	2.36%	600,000	14,148
24	2020 Series B	02/26/20	03/01/50	2.950%	500,000	99.96%	1.1%	98.89%	3.01%	500,000	15,031
25	2020 Series C	04/06/20	03/01/31	2.625%	600,000	99.83%	0.8%	99.00%	2.73%	600,000	16,387
26	2021 Green Series A 110087	03/29/21	04/01/28	1.900%	575,000	99.92%	0.9%	99.06%	2.04%	575,000	11,756
27	2021 Green Series B 110088	03/29/21	04/01/51	3.250%	425,000	99.17%	1.1%	98.06%	3.35%	425,000	14,250
28	1995CC 2021 Remarketing 110089	09/01/21	09/01/30	1.450%	82,350	100.00%	0.7%	99.32%	1.53%	82,350	1,261
29	2008ET2 2021 Remarketing 110090	09/01/21	08/01/29	1.350%	59,175	100.00%	0.7%	99.31%	1.44%	59,175	854
30	2022 Series A 110091	02/24/22	03/01/32	3.000%	500,000	99.60%	0.9%	98.70%	3.15%	500,000	15,764
31	2022 Green Series B 110092	02/24/22	03/01/52	3.650%	400,000	99.39%	1.1%	98.26%	3.75%	400,000	14,988
									3.77%	9,571,525	360,835

Michigan Public Service Commission
DTE Electric Company
Historical Cost of Short-Term Debt
Twelve Month Period Ended December 31, 2022

Case No.: U-21534
Exhibit: A-4
Schedule: D3
Witness: T. J. Lepczyk
Page: 1 of 1

Line No.	(a) Description	(b) Amount	(c) Source
Short Term Debt:			
1	Short Term Interest Expense	\$ 8,525	Company Books
2	Commitment Fees	<u>1,047</u>	Company Books
3	Total	<u>\$ 9,572</u>	
4	13 mo. Avg. short term borrowings	<u>\$ 348,184</u>	Exhibit A-2 B6.2, Column (d), Line 94
5	Short Term Debt Cost Rate	<u>2.75%</u>	Line 3 ÷ Line 4

**Michigan Public Service Commission
DTE Electric Company
Historical Cost of Preferred and Preference Stock
Twelve Month Period Ended December 31, 2022**

Case No.: U-21534
Exhibit: A-4
Schedule: D4
Witness: T. J. Lepczyk
Page: 1 of 1

The Company had no Preferred or Preference Stock outstanding during the
twelve month period ending December 31, 2022

**Michigan Public Service Commission
DTE Electric Company
Historical Cost of Common Shareholders' Equity
Twelve Month Period Ended December 31, 2022**

Case No.: U-21534
Exhibit: A-4
Schedule: D5
Witness: T. J. Lepczyk
Page: 1 of 1

U-20836 approved Cost of Common Shareholders' Equity

9.9%

Michigan Public Service Commission
DTE Electric Company
Annual Service Area Sales By Major Customer Classes And System Output
2018-2022 Historical

Case No. : U-21534
Exhibit: A-5
Schedule: E1
Witness: M.B. Leuker
Page: 1 of 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	<u>Annual Sales - GWh</u>						<u>Losses & Company Use</u>		<u>System</u>
<u>Line</u>	<u>No.</u>	<u>Year</u>	<u>Residential</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Other</u>	<u>Total</u>	<u>(GWh)</u>	<u>% Of</u>
									<u>Output</u>
									<u>(GWh)</u>
1	2018	15,939	11,271	21,093	224	48,527	3,645	7.0%	52,172
2	2019	15,066	10,948	20,382	226	46,623	3,493	7.0%	50,116
3	2020	16,316	10,086	17,759	220	44,381	3,470	7.3%	47,851
4	2021	16,387	10,768	18,469	216	45,839	3,541	7.2%	49,380
5	2022	15,844	10,848	18,481	210	45,383	3,601	7.4%	48,985

Michigan Public Service Commission
DTE Electric Company
Annual Bundled Sales By Major Customer Classes And System Output
2018-2022 Historical

Case No. : U-21534
Exhibit: A-5
Schedule: E1
Witness: M.B. Leuker
Page: 2 of 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	<u>Annual Sales - GWh</u>						<u>Losses & Company Use</u>		<u>System</u>
Line								% Of	Output
<u>No.</u>	<u>Year</u>	<u>Residential</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Other</u>	<u>Total</u>	<u>(GWh)</u>	<u>Output</u>	<u>(GWh)</u>
1	2018	15,939	10,343	17,284	224	43,789	3,340	7.1%	47,129
2	2019	15,066	10,083	16,698	226	42,073	2,868	6.4%	44,940
3	2020	16,315	9,329	14,765	220	40,629	2,566	5.9%	43,196
4	2021	16,386	9,938	14,943	216	41,482	3,098	6.9%	44,580
5	2022	15,844	10,014	14,830	210	40,898	3,092	7.0%	43,990

Michigan Public Service Commission
DTE Electric Company
Annual Electric Choice Sales By Major Customer Classes
2018-2022 Historical

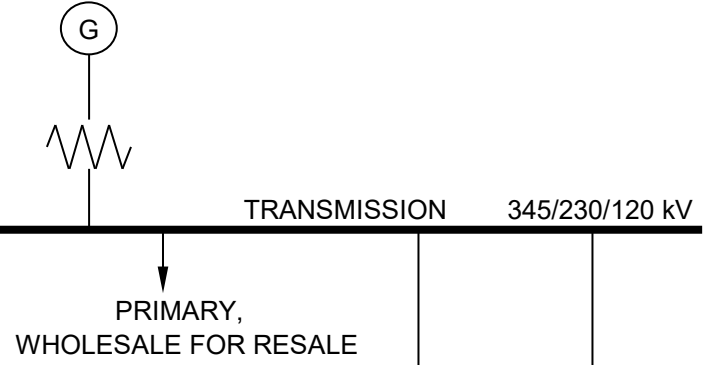
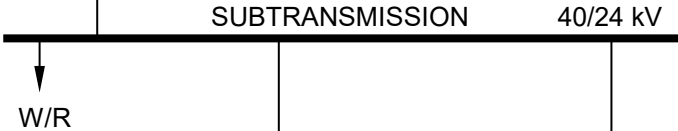
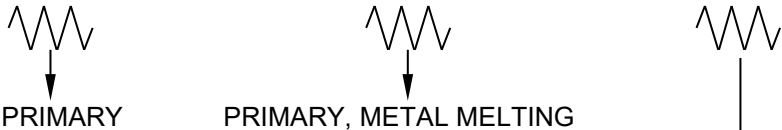
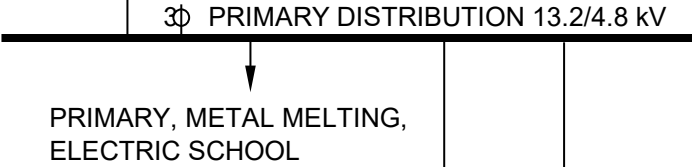
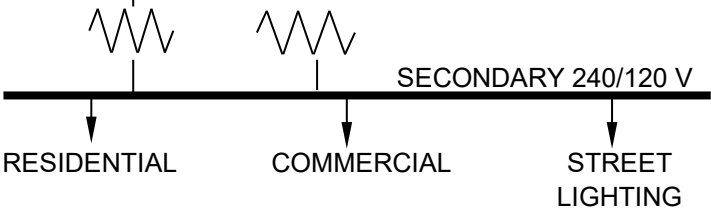
Case No. : U-21534
Exhibit: A-5
Schedule: E1
Witness: M.B. Leuker
Page: 3 of 4

	(a)	(b)	(c)	(d)	(e)	(f)
	<u>Annual Sales - GWh</u>					
Line						
<u>No.</u>	<u>Year</u>	<u>Residential</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Other</u>	<u>Total</u>
1	2018	0	928	3,809	0	4,737
2	2019	1	866	3,684	0	4,550
3	2020	1	757	2,994	0	3,751
4	2021	1	830	3,526	0	4,357
5	2022	0	834	3,651	0	4,486

Michigan Public Service Commission
DTE Electric Company
Annual Weather-Normalized Sales by Major Customer Classes
(2008-2022 15-Year Weather Normalization)
2018-2022 Historical

Case No. : U-21534
Exhibit: A-5
Schedule: E1
Witness: M.B. Leuker
Page: 4 of 4

<u>Weather-Normalized Annual Electric Sales - GWh</u>							
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line							Peak
No.	Year	<u>Residential</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Other</u>	<u>Total</u>	<u>Demand (MW)</u>
1	<u>Service Area</u>						
2	2018	15,138	11,055	20,945	224	47,362	11,344
3	2019	15,111	10,960	20,410	226	46,708	11,145
4	2020	16,246	10,180	17,811	220	44,457	11,246
5	2021	16,224	10,716	18,391	216	45,547	11,358
6	2022	15,689	10,790	18,428	210	45,117	10,959
7	<u>Bundled</u>						
8	2018	15,138	10,126	17,137	224	42,625	10,447
9	2019	15,110	10,095	16,726	226	42,158	10,355
10	2020	16,245	9,423	14,817	220	40,706	10,578
11	2021	16,223	9,886	14,866	216	41,190	10,552
12	2022	15,689	9,956	14,777	210	40,631	10,207
13	<u>Electric Choice</u>						
14	2018	0	928	3,809	0	4,737	939
15	2019	1	866	3,684	0	4,550	888
16	2020	1	757	2,994	0	3,751	748
17	2021	1	830	3,526	0	4,357	871
18	2022	0	834	3,651	0	4,486	852

ALLOCATIONS		FUNCTIONALIZED PLANT	ELECTRICAL SYSTEM SCHEMATIC DIAGRAM	
SCHEDULES	LOAD CHARACTERISTICS			
200A & 200B	AVG. MO. PEAK	PRODUCTION, BULK POWER LINES AND EQUIPMENT		
201	AVG. MO. PEAK	STATIONS AND EQUIPMENT		
202	NC CLASS PEAK	SUBTRANSMISSION LINES		
203	NC CLASS PEAK	SUBSTATIONS		
204	NC CLASS PEAK	THREE PHASE PRIMARY LINES		
205	NC CLASS PEAK	SINGLE PHASE PRIMARY LINES		
300	NC CUSTOMER MAX. DEMAND	DISTRIBUTION LINE TRANSFORMERS AND SECONDARY LINES		

Michigan Public Service Commission
DTE Electric Company
Allocation Schedule Description

Case No.: U-21534
Exhibit: A-5
Schedule: E3
Witness: A. Willis
Page: 1 of 2

	(a)	(b)	(c)	(d)
Line	Schedule	Portion of Electrical System	Description/Basis	Measurement Basis
1	100	Power Plant Energy Production	Based on Annual Energy	Total Energy
2				
3	200A	Production System Output 12CP	Based on the Transmission System 12 CP	12 CP Demand
4				
5	200B	Production System Output 4CP	Based on DTE Electric Bundled Service 4 CP; includes interruptible demand credits	4 CP Demand
6				
7	201	Input to Transmission Substation	Based on DTE Electric Service Territory 12 CP; includes interruptible demand credits	12 CP Demand
8				
9				
10	202A, B, C	Sub Transmission Lines	Based on loads from customer-owned, single-customer and joint-use substations; excludes subtransmission and transmission loads	Non-Coincident and Individual Customer Maximum Demands
11				

Michigan Public Service Commission
DTE Electric Company
Allocation Schedule Description

Case No.: U-21534
Exhibit: A-5
Schedule: E3
Witness: A. Willis
Page: 2 of 2

(a)		(b)	(c)	(d)
Line No.	Schedule	Portion of Electrical System	Description/Basis	Measurement Basis
1	203A	Primary Voltage Substation	Based on loads from primary voltage substations, excludes transmission and subtransmission loads	Non-Coincident and Individual Customer Maximum Demands
2				
3				
4	203B	Primary Voltage Substation	Based on loads from primary voltage substations; includes transmission and subtransmission loads from DTE Owned Substations; excludes subtransmission and transmission loads from Customer Owned Substations	Non-Coincident and Individual Customer Maximum Demands
5				
6				
7	203C	Primary Voltage Substation	Based on loads from primary voltage substations; includes loads from primary, secondary, transmission industrial and subtransmission industrial customers; excludes transmission bulk and subtransmission bulk voltage level customers, and excludes loads from customer owned substations.	Non-Coincident and Individual Customer Maximum Demands
8				
9				
10				
11	204	Primary Lines	Based on loads served by primary voltage distribution lines	Non-Coincident Demand
12				
13	205	Secondary Line Transformers	Based on loads at the secondary voltage line transformers	Non-Coincident Demand
14				
15	300	Secondary Distribution Lines	Based on loads served by secondary voltage distribution lines	Individual Customer Maximum
16				

Michigan Public Service Commission
DTE Electric Company
Planned Long Range Generation Changes (Steam, Hydraulic, & Other)
Years 2022 through 2032

Case No.: U-21534
Exhibit: A-6
Schedule: F1
Witness: M. E. Guillaumin
Page: 1 of 1

Line No.	Year	Increase (Decrease) in Summer Net Demonstrated Capacity (MW)	Cumulative Increase (Decrease) in Summer Net Demonstrated Capacity (MW)	Description of the Change in Capacity
1	2022	(399)	(399)	Retirement St. Clair Units 2 & 3 (-314 MW)
2				Retirement St. Clair Unit 6 (-311 MW)
3				Retirement St. Clair Unit 7 (-440 MW)
4				Retirement Trenton Channel Unit 9 (-495 MW)
5				Blue Water Energy Center - CCGT (1,127 MW)
6				Ludington Unit 3 Upgrade (34 MW)
7				
8	2023	(29)	(428)	Retirement of Northeast 11-1 Peaker (-15 MW)
9				Retirement of Slocum 11 Peakers (-14 MW)
10				
11	2024	(2)	(430)	Retirement of River Rouge 11 Peakers (-11 MW)
12				Retirement of St. Clair 12 Peakers (-5 MW)
13				Slocum BESS (14 MW)
14				
15	2025	(25)	(455)	Suspension of Fermi 11-3 and 11-4 Peakers (-25 MW)
16				Belle River Unit 1 Conversion to Natural Gas (0 MW change)
17				
18	2026	220	(235)	Trenton Channel BESS (220 MW)
19				Belle River Unit 2 Conversion to Natural Gas (0 MW change)
20				
21	2027	0	(235)	No forecasted changes
22				
23	2028	(1,260)	(1,495)	Retirement of Monroe Units 3 & 4 (-1,535 MW)
24				BESS (275 MW)
25				
26	2029	0	(1,495)	No forecasted changes
27				
28	2030	0	(1,495)	No forecasted changes
29				
30	2031	0	(1,495)	No forecasted changes
31				
32	2032	(1,531)	(3,026)	Retirement of Monroe Units 1 & 2 (-1,531 MW)

Michigan Public Service Commission
DTE Electric Company
Energy Supply Coal and Combined Cycle Unit Performance
Years 2019 through 2028

Case No.: U-21534
Exhibit: A-6
Schedule: F2
Witness: M. E. Guillaumin
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)
Line No.	Year	EAF	POF	ROF	
1	2019	73.4%	17.2%	9.4%	Actual
2	2020	68.9%	19.8%	11.4%	Actual
3	2021	71.7%	15.5%	12.8%	Actual
4	2022	72.7%	12.6%	14.7%	Actual
5	2023	80.2%	11.6%	8.2%	Actual
6	2024	77.7%	14.7%	7.6%	Forecasted
7	2025	78.5%	14.2%	7.4%	Forecasted
8	2026	76.5%	15.6%	7.9%	Forecasted
9	2027	81.9%	9.5%	8.5%	Forecasted
10	2028	85.6%	5.3%	9.0%	Forecasted
11	2019-2023	73.4%	15.3%	11.3%	Actual
12	2024-2028	80.0%	11.9%	8.1%	Forecasted

Michigan Public Service Commission
DTE Electric Company
Projected Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-11
 Schedule: A1
 Witness: K. M. Vangilder
 Page: 1 of 1

(a)		(b)	(c)
Line No.	Description	Source	Amount
1	Rate Base	Exh. A-12, Sch. B1	\$ 22,107,989
2	Adjusted Net Operating Income (1)	Exh. A-13, Sch. C1	\$ 1,087,100
3	Overall Rate of Return	Line 2 ÷ Line 1	4.92%
4	Projected Rate of Return	Exh. A-14, Sch. D1	5.92%
5	Income Requirements	Line 1 x Line 4	\$ 1,309,478
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	\$ 222,378
7	Revenue Conversion Factor	Exh. A-13, Sch. C2	<u>1.3496</u>
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	\$ 300,129
9	Return On - Tree Trim Regulatory Asset	Exh. A-11, Sch. A1.1	18,786
10	Return On - Monroe Regulatory Asset	Exh. A-11, Sch. A1.2	<u>137,518</u>
11	Revenue Deficiency / (Sufficiency)-Total	Sum Lines 8, 9, 10	<u>\$ 456,434</u>

Michigan Public Service Commission
DTE Electric Company
Tree Trim Regulatory Asset - Return On
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-11
Schedule: A1.1
Witness: K. M. Vangilder
Page: 1 of 1

(a)		(b)		(c)					
Line No.	Description	Test Period Amount		Reference					
1	<u>Return on Tree Trim Regulatory Asset</u>								
2	Average Balance Regulatory Asset		275,450		Line 16				
3	Deferred Tax Liability		(71,342)		- Line 2 x 25.9% Composite Tax Rate				
4	Average Net Rate Base		204,108						
5	Authorized Rate of Return on Permanent Capital (pretax)		9.20%		Exhibit A-14, Schedule D1				
6	Return on Tree Trim		18,786						
		2019-A	2020-A	2021-A	2022-A	2023	2024	2025	
7	<u>Tree Trim Regulatory Asset</u>								
8	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	67,000	52,700	43,700	Exhibit A-13 C5.6.1, Line 2
9	Carrying Charges through April 30, 2020 1/		1,200						
10	Additional Funding Request	-	-	-	-	-	-	87,000	Exhibit A-13 C5.6.1, Line 3
11	Total Tree Trim Reg Asset Deferral	43,300	75,300	70,500	58,200	67,000	52,700	130,700	
12	Total Tree Trim Reg Asset Cumulative	43,300	118,600	189,100	247,300	157,400	210,100	340,800	Cumulative Line 11
13	Approved for Securitization 2/				(156,900)				Case U-21015
14	Cumulative Balance at December 31				90,400	157,400	210,100	340,800	
15	Cumulative Balance at December 31						210,100	340,800	Assumes 100% of annual spend
16	Average Balance							275,450	

1/ Interest at U-20162 authorized STD rate of 3.56% until U-20561 order was in effect.

2/ Securitization approved per U-21015 order dated June 23, 2021 (up to \$156.9 per order page 91)

Michigan Public Service Commission
DTE Electric Company
Monroe Regulatory Asset - Return On
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-11
 Schedule: A1.2
 Witness: K. M. Vangilder
 Page: 1 of 1

	(a)	(b)	(c)
Line		Test Period	
No.	Description	Amount	Reference
1	<u>Return on Monroe Regulatory Asset</u>		
2	Monroe Regulatory Asset - Average Balance	2,093,063	Exhibit A-12, Schedule B4.4, Line 8
3	Pre-tax Weighted Average Cost of Capital 1/	6.57%	Exhibit A-14, Schedule D1, Page 2
4	Return on Monroe Regulatory Asset	<u>137,518</u>	

1/ Pretax WACC as proposed in this case was recalculated using 9% ROE in accordance with U-21193 order dated July 26, 2023

Michigan Public Service Commission
DTE Electric Company
Projected Financial Metrics* - Ratemaking Basis
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21534
 Exhibit: A-11
 Schedule: A2
 Witness: T. J. Lepczyk
 Page: 1 of 3

	(a)	(b)	(c)
		Fiscal Year	
Line No.	Description	No Rate Relief December 31, 2025	Full Rate Relief December 31, 2025
	<u>Return on Equity</u>		
1	Operating Revenue	5,465	5,766
2	Operating Expenses	(4,269)	(4,269)
3	Pre-Tax Operating Income	1,196	1,496
4	Income Taxes	(169)	(247)
5	Net Operating Income	1,027	1,249
6	Other Income and Deductions, incl AFUDC	60	60
7	Interest Charges	(397)	(397)
8	Preferred Stock Dividends	-	-
9	Net Income	690	912
10	Return Assignable to JDITC	(2)	(2)
11	Net Income Available for Common	688	911
12	Average Common Equity	8,674	8,674
13	Earned Rate of Return on Common Equity	7.9%	10.5%
14	Requested Return on Equity	10.5%	10.5%
	<u>EBIT Interest Coverage Ratio</u>		
15	Pre-Tax Operating Income	1,196	1,496
16	Other Income and Deductions, incl AFUDC	60	60
17	AFUDC - equity	(39)	(39)
18	Total EBIT	1,157	1,457
19	Interest Charges	397	397
20	EBIT Interest Coverage Ratio	2.9	3.7

Michigan Public Service Commission
DTE Electric Company
Projected Financial Metrics* - Ratemaking Basis
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21534
 Exhibit: A-11
 Schedule: A2
 Witness: T. J. Lepczyk
 Page 2 of 3

Line No.	Description	(a)	(b)	(c)
		Fiscal Year		
		No Rate Relief December 31, 2025	Full Rate Relief December 31, 2025	
	<u>EBITDA Interest Coverage Ratio</u>			
21	Total EBIT	1,157	1,457	
22	Depreciation and Amortization	1,266	1,266	
23	Total EBITDA	2,423	2,723	
24	Interest Charges	397	397	
25	EBITDA Interest Coverage Ratio	6.1	6.9	
	<u>Funds Flow from Operations (FFO) Interest Coverage Ratio</u>			
26	Net Income	690	912	
27	Depreciation and Amortization	1,266	1,266	
28	Deferred Income Tax	87	87	
29	AFUDC - equity	(39)	(39)	
30	Other Major Recurring Non-Cash Items	-	-	
31	Interest Paid	397	397	
32	Subtotal - FFO	2,401	2,624	
33	Interest Charges	397	397	
34	FFO Interest Coverage Ratio	6.0	6.6	
	<u>Overall Fixed Charge Coverage Ratio</u>			
35	Net Income	690	912	
36	Interest Charges	397	397	
37	Subtotal Numerator	1,087	1,309	
38	Interest Charges	397	397	
39	Preferred Stock Dividends	-	-	
40	Subtotal Denominator	397	397	
41	Overall Fixed Charge Coverage Ratio	2.7	3.3	

Michigan Public Service Commission
DTE Electric Company
Projected Financial Metrics* - Ratemaking Basis
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21534
 Exhibit: A-11
 Schedule: A2
 Witness: T. J. Lepczyk
 Page 3 of 3

	(a)	(b)	(c)
		Fiscal Year	
Line No.	Description	No Rate Relief December 31, 2025	Full Rate Relief December 31, 2025
	<u>Cash Flow Coverage of Dividends Ratio</u>		
42	Net Income	690	912
43	Depreciation and Amortization	1,266	1,266
44	Deferred Taxes	87	87
45	Subtotal	2,043	2,266
46	Common Dividends	848	848
47	Cash Flow Coverage of Dividends Ratio	2.4	2.7
	<u>Common Dividends Payout Ratio</u>		
48	Common Dividends	848	848
49	Net Income	690	912
50	Common Dividends Payout Ratio	123%	93%
	<u>Permanent Capitalization</u>		
51	Long Term Debt	8,664	8,664
52	Preferred Stock	-	-
53	Common Equity	8,674	8,674
54	Total Permanent Capital	17,337	17,337
55	Long Term Debt	50.0%	50.0%
56	Preferred Stock	- %	- %
57	Common Equity	50.0%	50.0%
58	Total Permanent Capital	100.0%	100.0%

* Each rating agency has its own methodology for calculating financial ratios. The adjustments used by the rating agencies are not readily available. The standard methodology for calculating ratios has been used in the financial metric calculations above.

Michigan Public Service Commission

DTE Electric Company

Projected Rate Base

Periods Ending December 31, 2022 and December 31, 2025

(\$000)

Case No.: U-21534

Exhibit: A-12

Schedule: B1

Witness: K. M. Vangilder

Page: 1 of 1

Line No.	(a) Description	(b) Source	(c)	(d)
			Historical Rate Base 12/31/2022 (13 Month Average)	Projected Rate Base 12/31/2025 (13 Month Average)
1	<u>Utility Plant in Service:</u>			
2	Plant in Service	Exh. A-12, Sch. B2, L6	24,545,204	24,872,100
3	Plant Held for Future Use	Exh. A-12, Sch. B2, L7	57,100	22,532
4	Construction Work in Progress	Exh. A-12, Sch. B2, L8	1,704,966	2,450,590
5	Acquisition Adjustments	Exh. A-12, Sch. B2, L9	100,705	83,332
6	Total Utility Plant	Sum Lines 2 thru 5	26,407,974	27,428,555
7	Depreciation Reserve	Exh. A-12, Sch. B3, L6	(7,685,530)	(6,777,289)
8	Net Utility Plant	Line 6 + Line 7	18,722,444	20,651,266
9	Net Capital Lease Property	Exh. A-12, Sch. B4.1, col. (c), L10	8,844	6,051
10	Property under Operating Leases	Exh. A-12, Sch. B4.1, col. (c), L11	-	-
11	Net Nuclear Fuel Property	Exh. A-12, Sch. B4.1, col. (c), L12	188,783	162,350
12	Total Utility Property and Plant	Sum Lines 8 thru 11	18,920,071	20,819,666
13	Less: Capital Lease Obligations	Exh. A-12, Sch. B4.1, col. (c), L85 + L100	10,272	7,049
14	Net Plant	Line 12 - Line 13	18,909,799	20,812,617
15	Allowance for Working Capital	Exh. A-12, Sch. B4	1,206,978	1,295,372
16	Total Rate Base	Line 14 + Line 15	20,116,777	22,107,989

Source Reference:

Historical Ending 12/31/2022 Balances: Exh. A-2, Sch. B5

Projected Average 12/31/2025 Balances: Exh. A-12, Sch. B4.1

Michigan Public Service Commission
DTE Electric Company
Projected Utility Plant
Periods Ending December 31, 2022 and December 31, 2025
(\$000)

Case No: U-21534
Exhibit: A-12
Schedule: B2
Witness: T. M. Uzenski
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(a)		(b)	(c)	(d)
Line No.	Description	MPSC Account No.	Historical Plant In Service 12/31/2022	Projected Plant In Service 12/31/2025
			(13 Month Average)	(13 Month Average)
1	Plant in Service	101	22,475,602	24,872,100
2	Plant Purchased or Sold	102	-	-
3	Experimental Plant Unclassified	103	-	-
4	Plant Leased from Others	104	-	-
5	Completed Construction Not Classified	106	2,069,602	-
6	Plant in Service		24,545,204	24,872,100
7	Plant Held for Future Use	105	57,100	22,532
8	Construction Work in Progress	107	1,704,966	2,450,590
9	Acquisition Adjustments	114	100,705	83,332
10	Total Utility Plant		26,407,974	27,428,555

Michigan Public Service Commission
DTE Electric Company
Projected Depreciation Reserve
Periods Ending December 31, 2022 and December 31, 2025
(\$000)

Case No: U-21534
Exhibit: A-12
Schedule: B3
Witness: T. M. Uzenski
Page: 1 of 1

(a)		(b)	(c)
Line No.	Description	Historical Accum. Depr. Reserve 12/31/2022	Projected Accum. Depr. Reserve 12/31/2025
		(13 Month Average)	(13 Month Average)
1	Intangible Plant		282,770
2	Production Plant		1,991,227
3	Transmission Plant		(6,196)
4	Distribution Plant		3,952,467
5	General Plant		557,020
6	Total Accumulated Depreciation Reserve	7,685,530	6,777,289

Michigan Public Service Commission
DTE Electric Company
Projected Working Capital
Periods Ending December 31, 2022 and December 31, 2025
(\$000)

Case No: U-21534
Exhibit: A-12
Schedule: B4
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b)		(c)	(d)
		Historical Working Capital 12/31/2022	Projected Working Capital 12/31/2025	Change	
		(13 Month Average)	(13 Month Average)	col. (c) - col. (b)	
1	<u>OTHER PROPERTY AND INVESTMENTS</u>				
2	Non-Current Portion of Allowances 1/	533	533	-	
3	Investment and Special Funds 1/	38,749	38,749	0	
4	Nuclear Decommissioning Trust Funds	-	0	0	
5	TOTAL OTHER PROPERTY & INVESTMENTS	39,282	39,282	0	
6	<u>CURRENT ASSETS</u>				
7	Cash 1/	11,011	11,011	-	
8	Notes Receivable	-	-	-	
9	Notes Receivable-Assoc. Co.	-	-	-	
10	Customer Accounts Receivable 1/	500,991	531,991	31,000	
11	Other Accounts Receivable 1/	82,804	82,804	-	
12	Other Accounts Receivable-Assoc. Co.	-	-	-	
13	Uncollectible Reserve 1/	(52,834)	(52,834)	-	
14	Unbilled Revenues 1/	275,981	275,981	-	
15	Inventories - Fuel 2/	164,835	169,363	4,527	
16	Inventories - Material and Supplies 1/	322,862	322,862	-	
17	Prepayments 2/	101,667	108,056	6,389	
18	Other Current Assets 1/	0	0	-	
19	TOTAL CURRENT ASSETS	1,407,318	1,449,234	41,917	
20	<u>DEFERRED DEBITS</u>				
21	Unamortized Loss on Reacquired Debt 2/	35,970	27,448	(8,522)	
22	Reg Asset - Fermi 2	-	0	0	
23	Def Debit - Prepaid Pension Asset 2/	636,559	694,569	58,010	
24	Reg Asset - Recoverable Pension & OPEB FAS 158	0	(0)	(0)	
25	Reg Asset - Pension Deferral	3,148	21,651	18,502	
26	Reg Asset - Monroe	-	-	-	
27	Reg Asset - Ludington	-	9,933	9,933	
28	Reg Asset - Transitional Recovery Mechanism (TRM)	-	-	-	
29	Reg Asset - Customer 360 2/	43,917	31,193	(12,725)	
30	Reg Asset - Tier 2 Plants	-	-	-	
31	Reg Asset - Residential Income Assistance 1/	2,241	2,241	-	
32	Reg Asset - Program Eval. Review Committee (PERC) 2/	32,473	2,875	(29,599)	
33	Reg Asset - Advanced Distribution Management System (ADMS) 2/	11,355	15,514	4,159	
34	Reg Asset - Charging Forward 2/	7,477	38,681	31,203	
35	Reg Asset - Enhanced Tree Trimming Program	-	-	-	
36	Reg Asset - Advanced Customer Pricing Pilot Costs 2/	6,494	3,190	(3,304)	
37	Reg Asset – Time of Day Deferred Project Costs 2/	152	5,784	5,632	
38	Reg Asset – Open 2/	-	-	-	
39	Reg Asset - Pension Capitalized 2/	18,285	(0)	(18,285)	
40	Reg Asset - Demand Response 2/	3,610	3,187	(423)	
41	Reg Asset - Incentive Deferral 2/	66	3,884	3,818	
42	Reg Asset - Low Income Assistance Tracker	52	24	(28)	
43	Reg Asset - Low Income Payment Stability Plan	438	1,043	605	
44	Reg Asset - TCJA Under Recovery	99	400	301	
45	Reg Asset - OPEN	-	-	-	
46	Def Debit - Preliminary Survey and Investigation Charges 2/	80	80	(0)	
47	Def Debit - Prepaid OPEB 2/	120,003	191,040	71,037	
48	Def Debit - Combined Operating License (COL)	-	-	-	
49	Def Debit - EWR Performance Incentive	-	-	-	
50	Other Deferred Debits 1/	23,399	38,306	14,907	
51	TOTAL DEFERRED DEBITS	945,820	1,091,042	145,222	
52	TOTAL ASSETS AND OTHER DEBITS	2,392,419	2,579,558	187,139	
53	<u>NON-CURRENT LIABILITIES</u>				
54	Accumulated Provision for Injuries and Damages 1/	38,139	38,139	-	
55	Accrued Post Retirement Benefits	(470)	0	470	
56	Accrued Pension Liabilities	(0)	(0)	(0)	
57	Other Non-Current Liabilities	(0)	(0)	0	
58	TOTAL NON-CURRENT LIABILITES	37,669	38,139	470	
59	<u>CURRENT LIABILITIES</u>				
60	Accounts Payable 1/	576,308	576,308	-	
61	Accounts Payable - Assoc. Co. 1/	73,784	73,784	-	
62	Taxes Payable 2/	5,091	8,040	2,948	
63	Interest Payable 2/	104,598	117,102	12,504	
64	Fermi 2 Outage Accrual 1/	11,993	25,923	13,931	
65	Other Current Liabilities 1/	168,651	168,651	-	
66	TOTAL CURRENT LIABILITIES	940,426	969,809	29,383	
67	<u>DEFERRED CREDITS</u>				
68	Regulatory Liab-Other Post Empl Benefits (OPEB) 2/	117,355	130,275	12,920	
69	Regulatory Liab-OPEB Capitalized 2/	63,042	95,172	32,130	
70	Regulatory Liab- Pension Capitalized 2/	-	23,843	23,843	
71	Regulatory Liab- Negative Pension 2/	-	-	-	
72	Fermi 2 Decommissioning	-	0	0	
73	Other Deferred Credits 1/	26,949	26,949	-	
74	TOTAL DEFERRED CREDITS	207,345	276,239	68,893	
75	TOTAL LIABILITIES AND OTHER CREDITS	1,185,441	1,284,186	98,746	
76	Total Working Capital	1,206,978	1,295,372	88,393	

1/ Designates accounts that are not volatile or known to have measurable changes. Historical balance at December 31 is adjusted to reflect the 13 month average which is used as a proxy for the projected test year.

2/ Designates accounts that have known and measurable changes projected forward from historical year-end Dec 31 through the projected test year.

Michigan Public Service Commission
DTE Electric Company
Projected Average Balance Sheet with Classifications - Assets
Projected Average Balances Period Ending December 31, 2025
(\$000)

Case No: U-21534
Exhibit: A-12
Schedule: B4.1
Witness: T. M. Uzenski
Page: 1 of 2

Line No.	(a) Description	(b) Total 13 Mo. Average 12/31/2025	(c) Net Plant	(d) Working Capital	(e) Common Equity	(f) Short Term Debt	(g) Long Term Debt	(h) Deferred Taxes	(i) Job Development Investment Tax Credits
1	ASSETS AND OTHER DEBITS								
2	<u>TOTAL UTILITY PLANT AND PROPERTY</u>								
3	TOTAL UTILITY PLANT								
4	Plant in Service	24,872,100	24,872,100	-	-	-	-	-	-
5	Plant Held for Future Use	22,532	22,532	-	-	-	-	-	-
6	Construction Work in Progress	2,450,590	2,450,590	-	-	-	-	-	-
7	Acquisition Adjustments	83,332	83,332	-	-	-	-	-	-
8	Depreciation Reserve	(6,777,289)	(6,777,289)	-	-	-	-	-	-
9	NET UTILITY PLANT	20,651,266	20,651,266	-	-	-	-	-	-
10	Net Capital Lease Property	6,051	6,051	-	-	-	-	-	-
11	Property under Operating Leases	-	-	-	-	-	-	-	-
12	Net Nuclear Fuel Property	162,350	162,350	-	-	-	-	-	-
13	TOTAL UTILITY PLANT AND PROPERTY	20,819,666	20,819,666	-	-	-	-	-	-
14	<u>OTHER PROPERTY AND INVESTMENTS</u>								
15	Non-Utility Property	-	-	-	-	-	-	-	-
16	Non-Current Portion of Allowances	533	-	533	-	-	-	-	-
17	Investment and Special Funds	38,749	-	38,749	-	-	-	-	-
18	Nuclear Decommissioning Trust Funds	0	-	0	-	-	-	-	-
19	TOTAL OTHER PROPERTY & INVESTMENTS	39,282	-	39,282	-	-	-	-	-
20	<u>CURRENT ASSETS</u>								
21	Cash	11,011	-	11,011	-	-	-	-	-
22	Notes Receivable	-	-	-	-	-	-	-	-
23	Notes Receivable-Assoc. Co.	-	-	-	-	-	-	-	-
24	Customer Accounts Receivable	531,991	-	531,991	-	-	-	-	-
25	Other Accounts Receivable	82,804	-	82,804	-	-	-	-	-
26	Other Accounts Receivable-Assoc. Co.	-	-	-	-	-	-	-	-
27	Uncollectible Reserve	(52,834)	-	(52,834)	-	-	-	-	-
28	Unbilled Revenues	275,981	-	275,981	-	-	-	-	-
29	Inventories - Fuel	169,363	-	169,363	-	-	-	-	-
30	Inventories - Material and Supplies	322,862	-	322,862	-	-	-	-	-
31	Prepayments	108,056	-	108,056	-	-	-	-	-
32	Other Current Assets	0	-	0	-	-	-	-	-
33	TOTAL CURRENT ASSETS	1,449,234	-	1,449,234	-	-	-	-	-
34	<u>DEFERRED DEBITS</u>								
35	Unamortized Debt Expense	80,851	-	-	-	-	80,851	-	-
36	Unamortized Loss on Reacquired Debt	27,448	-	27,448	-	-	-	-	-
37	Reg Asset - Fermi 2	0	-	0	-	-	-	-	-
38	Def Debit - Prepaid Pension Asset	694,569	-	694,569	-	-	-	-	-
39	Reg Asset - Recoverable Pension & OPEB FAS 158	(0)	-	(0)	-	-	-	-	-
40	Reg Asset - Pension Deferral	21,651	-	21,651	-	-	-	-	-
41	Reg Asset - Monroe	-	-	-	-	-	-	-	-
42	Reg Asset - Ludington	9,933	-	9,933	-	-	-	-	-
43	Reg Asset - Transitional Recovery Mechanism (TRM)	-	-	-	-	-	-	-	-
44	Reg Asset - Customer 360	31,193	-	31,193	-	-	-	-	-
45	Reg Asset - Tier 2 Plants	-	-	-	-	-	-	-	-
46	Reg Asset - Residential Income Assistance	2,241	-	2,241	-	-	-	-	-
47	Reg Asset - Program Eval. Review Committee (PERC)	2,875	-	2,875	-	-	-	-	-
48	Reg Asset - Advanced Distribution Management System	15,514	-	15,514	-	-	-	-	-
49	Reg Asset - Charging Forward	38,681	-	38,681	-	-	-	-	-
50	Reg Asset - Enhanced Tree Trimming Program	-	-	-	-	-	-	-	-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	3,190	-	3,190	-	-	-	-	-
52	Reg Asset - Time of Day Deferred Project Costs	5,784	-	5,784	-	-	-	-	-
53	Reg Asset - Open	-	-	-	-	-	-	-	-
54	Reg Asset - Pension Capitalized	(0)	-	(0)	-	-	-	-	-
55	Reg Asset - Demand Response	3,187	-	3,187	-	-	-	-	-
56	Reg Asset - Incentive Deferral	3,884	-	3,884	-	-	-	-	-
57	Reg Asset - Low Income Assistance Tracker	24	-	24	-	-	-	-	-
58	Reg Asset - Low Income Payment Stability Plan	1,043	-	1,043	-	-	-	-	-
59	Reg Asset - TCJA Under Recovery	400	-	400	-	-	-	-	-
60	Reg Asset - OPEN	-	-	-	-	-	-	-	-
61	Def Debit - Preliminary Survey and Investigation Charge	80	-	80	-	-	-	-	-
62	Def Debit - Prepaid OPEB	191,040	-	191,040	-	-	-	-	-
63	Def Debit - Combined Operating License (COL)	-	-	-	-	-	-	-	-
64	Def Debit - EWR Performance Incentive	-	-	-	-	-	-	-	-
65	Def Debit - Misc Tax Related	148,261	-	-	-	-	-	148,261	-
66	Recoverable Income Taxes	7,762	-	-	-	-	-	7,762	-
67	Accumulated Deferred Income Tax Asset	-	-	-	-	-	-	-	-
68	Other Deferred Debits	38,306	-	38,306	-	-	-	-	-
69	TOTAL DEFERRED DEBITS	1,327,917	-	1,091,042	-	-	80,851	156,023	-
70	TOTAL ASSETS AND OTHER DEBITS	23,636,099	20,819,666	2,579,558	-	-	80,851	156,023	-

Michigan Public Service Commission
DTE Electric Company
Projected Average Balance Sheet with Classifications - Liabilities
Projected Average Balances Period Ending December 31, 2025
(\$000's)

Case No: U-21534
Exhibit: A-12
Schedule: B4.1
Witness: T. M. Uzenski
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Total 13 Mo. Average 12/31/2025	Net Plant	Working Capital	Common Equity	Short Term Debt	Long Term Debt	Deferred Taxes	Job Development Investment Tax Credits
71	LIABILITIES AND OTHER CREDITS								
72	<u>CAPITALIZATION</u>								
73	Long-Term Debt								
74	Bonds Outstanding	8,766,231	-	-	-	-	8,766,231	-	-
75	Net Premium/Discount	(21,458)	-	-	-	-	(21,458)	-	-
76	Total Long-Term Debt	8,744,773	-	-	-	-	8,744,773	-	-
77	Preferred Stock	-	-	-	-	-	-	-	-
78	Common Equity								
79	Common Stock	7,359,850	-	-	7,359,850	-	-	-	-
80	Retained Earnings	1,313,678	-	-	1,313,678	-	-	-	-
81	Other Comprehensive Income	(0)	-	-	(0)	-	-	-	-
82	Total Common Equity	8,673,528	-	-	8,673,528	-	-	-	-
83	TOTAL CAPITALIZATION	17,418,302	-	-	8,673,528	-	8,744,773	-	-
84	<u>NON-CURRENT LIABILITIES</u>								
85	Capital Leases - Non-Current	545	545	-	-	-	-	-	-
86	Operating Leases - Non-Current	-	-	-	-	-	-	-	-
87	Accumulated Provision for Injuries and Damages	38,139	-	38,139	-	-	-	-	-
88	Accrued Post Retirement Benefits	0	-	0	-	-	-	-	-
89	Accrued Pension Liabilities	(0)	-	(0)	-	-	-	-	-
90	Asset Retirement Obligations	(0)	-	(0)	-	-	-	-	-
91	Other Non-Current Liabilities	(0)	-	(0)	-	-	-	-	-
92	TOTAL NON-CURRENT LIABILITIES	38,683	545	38,139	-	-	-	-	-
93	<u>CURRENT LIABILITIES</u>								
94	Short-Term Debt	509,454	-	-	-	509,454	-	-	-
95	Notes Payable - Assoc. Co.	-	-	-	-	-	-	-	-
96	Accounts Payable	576,308	-	576,308	-	-	-	-	-
97	Accounts Payable - Assoc. Co.	73,784	-	73,784	-	-	-	-	-
98	Taxes Payable	8,040	-	8,040	-	-	-	-	-
99	Interest Payable	117,102	-	117,102	-	-	-	-	-
100	Capital Leases - Current	6,504	6,504	-	-	-	-	-	-
101	Operating Leases - Current	-	-	-	-	-	-	-	-
102	Fermi 2 Outage Accrual	25,923	-	25,923	-	-	-	-	-
103	Other Current Liabilities	168,651	-	168,651	-	-	-	-	-
104	TOTAL CURRENT LIABILITIES	1,485,767	6,504	969,809	-	509,454	-	-	-
105	<u>DEFERRED CREDITS</u>								
106	Regulatory Liab-Renewable Energy Program	-	-	-	-	-	-	-	-
107	Regulatory Liab-Energy Optimization	-	-	-	-	-	-	-	-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	130,275	-	130,275	-	-	-	-	-
109	Regulatory Liab-OPEB Capitalized	95,172	-	95,172	-	-	-	-	-
110	Regulatory Liab- Pension Capitalized	23,843	-	23,843	-	-	-	-	-
111	Regulatory Liab- Negative Pension	-	-	-	-	-	-	-	-
112	Fermi 2 Decommissioning	0	-	0	-	-	-	-	-
113	Accumulated Deferred Income Taxes	3,102,498	-	-	-	-	-	3,102,498	-
114	Accumulated Deferred Investment Tax Credit	31,485	-	-	-	-	-	-	31,485
115	Tax Reform Reg Liab-Refundable Income Taxes	1,283,126	-	-	-	-	-	1,283,126	-
116	Other Deferred Credits	26,949	-	26,949	-	-	-	-	-
117	TOTAL DEFERRED CREDITS	4,693,347	-	276,239	-	-	-	4,385,623	31,485
118	TOTAL LIABILITIES AND OTHER CREDITS	23,636,099	7,049	1,284,186	8,673,528	509,454	8,744,773	4,385,623	31,485
119	TOTAL ASSETS AND OTHER DEBITS	23,636,099	20,819,666	2,579,558	-	-	80,851	156,023	-
120	TOTAL LIABILITIES AND OTHER CREDITS	23,636,099	7,049	1,284,186	8,673,528	509,454	8,744,773	4,385,623	31,485
121	NET RATE BASE AND CAPITALIZATION	-	20,812,617	1,295,372	(8,673,528)	(509,454)	(8,663,922)	(4,229,600)	(31,485)

Note: Total Electric Balance Sheet includes Midwest Energy Resources Company

Michigan Public Service Commission

DTE Electric Company

Projected Balance Sheet

Balances Between Periods Ended 12/31/2022 and 12/31/2025

(\$000)

Case No.: U-21534

Exhibit: A-12

Schedule: B4.2

Witness: T. M. Uzenski

Page: 1 of 2

Line No.	(a) Description	(b) Mth Ended 12/31/2022	(c) Mth Ended 12/31/2024	(d) Mth Ended 12/31/2025	(e) 13 Month Average Ended 12/31/2022	(f) 13 Month Average Ending 12/31/2025
1	ASSETS AND OTHER DEBITS					
2	<u>TOTAL UTILITY PLANT AND PROPERTY</u>					
3	TOTAL UTILITY PLANT					
4	Plant in Service	24,584,064	24,227,364	25,646,532	24,545,204	24,872,100
5	Plant Held for Future Use	57,100	72,404	224	57,100	22,532
6	Construction Work in Progress	1,730,024	2,166,011	2,452,984	1,704,966	2,450,590
7	Acquisition Adjustments	97,810	86,228	80,437	100,705	83,332
8	Depreciation Reserve	(7,294,117)	(6,573,116)	(6,850,122)	(7,685,530)	(6,777,289)
9	NET UTILITY PLANT	19,174,880	19,978,892	21,330,055	18,722,444	20,651,266
10	Net Capital Lease Property	6,051	6,051	6,051	8,844	6,051
11	Property under Operating Leases	-	-	-	-	-
12	Net Nuclear Fuel Property	162,597	163,611	237,634	188,783	162,350
13	TOTAL UTILITY PLANT AND PROPERTY	19,343,528	20,148,553	21,573,740	18,920,071	20,819,666
14	<u>OTHER PROPERTY AND INVESTMENTS</u>					
15	Non-Utility Property	-	-	-	-	-
16	Non-Current Portion of Allowances	499	533	533	533	533
17	Investment and Special Funds	39,762	38,749	38,749	38,749	38,749
18	Nuclear Decommissioning Trust Funds	0	0	0	-	0
19	TOTAL OTHER PROPERTY & INVESTMENTS	40,262	39,282	39,282	39,282	39,282
20	<u>CURRENT ASSETS</u>					
21	Cash	14,562	11,011	11,011	11,011	11,011
22	Notes Receivable	-	-	-	-	-
23	Notes Receivable-Assoc. Co.	-	-	-	-	-
24	Customer Accounts Receivable	487,691	531,991	531,991	500,991	531,991
25	Other Accounts Receivable	76,246	82,804	82,804	82,804	82,804
26	Other Accounts Receivable-Assoc. Co.	-	-	-	-	-
27	Uncollectible Reserve	(48,870)	(52,834)	(52,834)	(52,834)	(52,834)
28	Unbilled Revenues	287,081	275,981	275,981	275,981	275,981
29	Inventories - Fuel	167,499	223,839	153,369	164,835	169,363
30	Inventories - Material and Supplies	330,816	322,862	322,862	322,862	322,862
31	Prepayments	66,313	76,944	84,858	101,667	108,056
32	Other Current Assets	0	0	0	0	0
33	TOTAL CURRENT ASSETS	1,381,337	1,472,599	1,410,042	1,407,318	1,449,234
34	<u>DEFERRED DEBITS</u>					
35	Unamortized Debt Expense	65,319	74,749	82,948	66,218	80,851
36	Unamortized Loss on Reacquired Debt	34,377	28,600	26,356	35,970	27,448
37	Reg Asset - Fermi 2	0	0	0	-	0
38	Def Debit - Prepaid Pension Asset	609,853	721,565	667,572	636,559	694,569
39	Reg Asset - Recoverable Pension & OPEB FAS 158	(0)	(0)	(0)	0	(0)
40	Reg Asset - Pension Deferral	40,930	5,514	37,787	3,148	21,651
41	Reg Asset - Monroe	-	-	-	-	-
42	Reg Asset - Ludington	-	9,933	9,933	-	9,933
43	Reg Asset - Transitional Recovery Mechanism (TRM)	-	-	-	-	-
44	Reg Asset - Customer 360	41,797	33,314	29,072	43,917	31,193
45	Reg Asset - Tier 2 Plants	-	-	-	-	-
46	Reg Asset - Residential Income Assistance	3,747	2,241	2,241	2,241	2,241
47	Reg Asset - Program Eval. Review Committee (PERC)	25,620	8,519	(2,770)	32,473	2,875
48	Reg Asset - Advanced Distribution Management System (ADMS)	13,849	16,107	14,921	11,355	15,514
49	Reg Asset - Charging Forward	11,193	30,581	47,071	7,477	38,681
50	Reg Asset - Enhanced Tree Trimming Program	-	-	-	-	-
51	Reg Asset - Advanced Customer Pricing Pilot Costs	6,489	3,850	2,530	6,494	3,190
52	Reg Asset - Time of Day Deferred Project Costs	1,979	6,631	4,938	152	5,784
53	Reg Asset - Open	-	-	-	-	-
54	Reg Asset - Pension Capitalized	32,418	(0)	(0)	18,285	(0)
55	Reg Asset - Demand Response	3,715	4,658	1,787	3,610	3,187
56	Reg Asset - Incentive Deferral	856	3,884	3,884	66	3,884
57	Reg Asset - Low Income Assistance Tracker	24	24	24	52	24
58	Reg Asset - Low Income Payment Stability Plan	1,043	1,043	1,043	438	1,043
59	Reg Asset - TCJA Under Recovery	400	400	400	99	400
60	Reg Asset - OPEN	-	-	-	-	-
61	Def Debit - Preliminary Survey and Investigation Charges	80	80	80	80	80
62	Def Debit - Prepaid OPEB	129,128	177,579	194,299	120,003	191,040
63	Def Debit - Combined Operating License (COL)	-	-	-	-	-
64	Def Debit - EWR Performance Incentive	-	-	-	-	-
65	Def Debit - Misc Tax Related	203,030	159,945	136,578	205,717	148,261
66	Recoverable Income Taxes	13,715	8,953	6,572	14,905	7,762
67	Accumulated Deferred Income Tax Asset	-	-	-	-	-
68	Other Deferred Debits	27,550	35,256	41,356	23,399	38,306
69	TOTAL DEFERRED DEBITS	1,267,112	1,333,425	1,308,622	1,232,659	1,327,917
70	TOTAL ASSETS AND OTHER DEBITS	22,032,240	22,993,859	24,331,686	21,599,330	23,636,099

Michigan Public Service Commission

DTE Electric Company

Projected Balance Sheet

Balances Between Periods Ended 12/31/2022 and 12/31/2025

(\$000)

Case No.: U-21534

Exhibit: A-12

Schedule: B4.2

Witness: T. M. Uzenski

Page: 2 of 2

Line No.	(a) Description	(b) Mth Ended 12/31/2022	(c) Mth Ended 12/31/2024	(d) Mth Ended 12/31/2025	(e) 13 Month Average Ended 12/31/2022	(f) 13 Month Average Ending 12/31/2025
71	LIABILITIES AND OTHER CREDITS					
72	<u>CAPITALIZATION</u>					
73	Long-Term Debt					
74	Bonds Outstanding	7,920,135	8,934,135	9,077,239	8,122,755	8,766,231
75	Net Premium/Discount	(22,222)	(22,034)	(20,882)	(22,251)	(21,458)
76	Total Long-Term Debt	<u>7,897,913</u>	<u>8,912,101</u>	<u>9,056,357</u>	<u>8,100,504</u>	<u>8,744,773</u>
77	Preferred Stock					
78	Common Equity					
79	Common Stock	6,601,958	7,154,696	7,962,696	6,140,301	7,359,850
80	Retained Earnings	1,531,387	1,468,743	1,311,204	1,563,474	1,313,678
81	Other Comprehensive Income	(0)	(0)	(0)	(0)	(0)
82	Total Common Equity	<u>8,133,345</u>	<u>8,623,439</u>	<u>9,273,900</u>	<u>7,703,775</u>	<u>8,673,528</u>
83	TOTAL CAPITALIZATION	<u>16,031,258</u>	<u>17,535,541</u>	<u>18,330,258</u>	<u>15,804,279</u>	<u>17,418,302</u>
84	<u>NON-CURRENT LIABILITIES</u>					
85	Capital Leases - Non-Current	545	545	545	3,799	545
86	Operating Leases - Non-Current	-	-	-	(0)	-
87	Accumulated Provision for Injuries and Damages	38,217	38,139	38,139	38,139	38,139
88	Accrued Post Retirement Benefits	0	0	0	(470)	0
89	Accrued Pension Liabilities	(0)	(0)	(0)	(0)	(0)
90	Asset Retirement Obligations	(0)	(0)	(0)	-	(0)
91	Other Non-Current Liabilities	(0)	(0)	(0)	(0)	(0)
92	TOTAL NON-CURRENT LIABILITIES	<u>38,761</u>	<u>38,683</u>	<u>38,683</u>	<u>41,468</u>	<u>38,683</u>
93	<u>CURRENT LIABILITIES</u>					
94	Short-Term Debt	208,303	(224,734)	264,899	167,142	509,454
95	Notes Payable - Assoc. Co.	-	-	-	-	-
96	Accounts Payable	636,531	576,308	576,308	576,308	576,308
97	Accounts Payable - Assoc. Co.	73,333	73,784	73,784	73,784	73,784
98	Taxes Payable	10,819	10,104	10,176	5,091	8,040
99	Interest Payable	104,161	126,764	111,512	104,598	117,102
100	Capital Leases - Current	6,504	6,504	6,504	6,474	6,504
101	Operating Leases - Current	-	-	-	-	-
102	Fermi 2 Outage Accrual	17,423	17,423	34,423	11,993	25,923
103	Other Current Liabilities	<u>182,447</u>	<u>168,651</u>	<u>168,651</u>	<u>168,651</u>	<u>168,651</u>
104	TOTAL CURRENT LIABILITIES	<u>1,239,522</u>	<u>754,806</u>	<u>1,246,259</u>	<u>1,114,042</u>	<u>1,485,767</u>
105	<u>DEFERRED CREDITS</u>					
106	Regulatory Liab-Renewable Energy Program	-	-	-	-	-
107	Regulatory Liab-Energy Optimization	-	-	-	-	-
108	Regulatory Liab-Other Post Empl Benefits (OPEB)	128,416	135,228	125,323	117,355	130,275
109	Regulatory Liab-OPEB Capitalized	72,629	92,302	97,971	63,042	95,172
110	Regulatory Liab- Pension Capitalized	-	26,618	21,098	-	23,843
111	Regulatory Liab- Negative Pension	-	-	-	-	-
112	Fermi 2 Decommissioning	0	0	0	-	0
113	Accumulated Deferred Income Taxes	3,001,595	3,035,030	3,164,627	2,853,174	3,102,498
114	Accumulated Deferred Investment Tax Credit	32,611	31,710	31,260	32,836	31,485
115	Tax Reform Reg Liab-Refundable Income Taxes	1,454,958	1,316,993	1,249,258	1,546,186	1,283,126
116	Other Deferred Credits	<u>32,489</u>	<u>26,949</u>	<u>26,949</u>	<u>26,949</u>	<u>26,949</u>
117	TOTAL DEFERRED CREDITS	<u>4,722,698</u>	<u>4,664,829</u>	<u>4,716,485</u>	<u>4,639,541</u>	<u>4,693,347</u>
118	TOTAL LIABILITIES AND OTHER CREDITS	<u>22,032,240</u>	<u>22,993,859</u>	<u>24,331,686</u>	<u>21,599,330</u>	<u>23,636,099</u>
119	TOTAL ASSETS -TOTAL LIABILITIES	-	-	-	0	-

Michigan Public Service Commission
DTE Electric Company
Common Equity Reconciliation
(\$000)

Case No: U-21534
Exhibit: A-12
Schedule: B4.3
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b) Amount	(c)
1	December 31, 2022 Common Equity Balance	8,133,345	Exh. A-12, Sch. B4.2, Line 82, Col (b)
2	1/1/2023 - 12/31/2024 Activity (24 Months)		
3	Net Income	1,416,797	
4	Dividend	(1,479,441)	
5	Equity Infusion	1,359,634	
6	Removal of Equity supporting Monroe Regulatory Asset	(806,896)	
7	Total Activity	<u>490,094</u>	
8	December 31, 2024 Common Equity Balance	8,623,439	Exh. A-12, Sch. B4.2, Line 82, Col (c)
9	1/1/2025 - 12/31/2025 Activity (12 Months)		
10	Net Income	689,993	
11	Dividend	(847,532)	
12	Equity Infusion	<u>808,000</u>	
13	Total Activity	<u>650,461</u>	
14	December 31, 2025 Common Equity Balance	<u><u>9,273,900</u></u>	Exh. A-12, Sch. B4.2, Line 82, Col (d)
15	13-Month Avg Common Equity Jan. 1, 2025 thru Dec. 31, 2025	<u><u>8,673,528</u></u>	Exh. A-12, Sch. B4.2, Line 82, Col (f)

Michigan Public Service Commission
DTE Electric Company
Monroe Regulatory Asset - Projected Balance
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-12
 Schedule: B4.4
 Witness: T. M. Uzenski
 Page: 1 of 1

Line No.	(a) Description	(b) 12/31/2023	(c) 12/31/2024	(d) 12/31/2025	(e) Bridge 12/31/2024	(f) Test 12/31/2025	(g) Reference
1	<u>Monroe Regulatory Asset</u>						
2	Beginning Balance	-	-	2,095,834	-	2,095,834	
3	Plant Transfer	-	2,095,834	-	2,095,834	-	Note 1/
4	Obsolete Inventory Reclass	-	-	-	-	-	
5	Expenditures	-	-	127,104	-	127,104	Exh. A-12, Sch. B5.1, Line 17
6	Amortization Expense	-	-	(144,067)	-	(144,067)	Note 2/
7	Ending Balance	-	2,095,834	2,078,871	2,095,834	2,078,871	
8	13- Month Average Balance					2,093,063	

1/ Regulatory asset authorized per U-21193 order dated July 26, 2023

2/ 15 year amortization beginning with test period on January 1, 2025 and ending December 31, 2039

Case No.: U-21534
Exhibit A-12
Schedule B4.5
Witness: T. M. Uzenski
Page: 1 of 1

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Monroe Power Plant												
2				col. (a) + (b)									
3		<i>Before</i>	<i>Reclass to</i>	<i>Remaining</i>									
4		<i>Reclass</i>	<i>Reg Asset</i>	<i>NBV</i>									
5		12/31/24		12/31/24	12/31/25	12/31/26	12/31/27	12/31/28	12/31/29	12/31/30	12/31/31	12/31/32	
6	Gross Plant	4,514	(3,422)	1,092	1,092	1,092	1,092	1,092	1,092	1,092	1,092	1,092	
7	CWIP	90	(90)	-	-	-	-	-	-	-	-	-	
8	Accum Dep (Investment only)	(1,416)	1,416	-	(31)	(62)	(93)	(123)	(154)	(185)	(216)	(247)	
9	Net Plant	3,188	(2,096)	1,092	1,061	1,030	999	969	938	907	876	845	Securitize Remaining NBV
10	No. of Amort Months				12	12	12	12	12	12	12	12	
11													
12		Note: Gross Plant depreciated over 96 months (1/1/2025-12/31/2032) results in Net Plant of \$845M (fixed amount per IRP Settlement in Case No. U-21193)											
13			Goal Seek:	845	NBV at: 12/31/32								
14				96	Months								
15				2.82%	Depreciation rate 2025-32 *								
16				1,092	Gross Plant after Reclass								
17		*Depreciation rate is Investment component only; Cost of removal component is excluded here but still expensed in base rates											

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Summary
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5
Witness: T. M. Uzenski
Page: 1 of 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Expenditures						Last Rate Case Approved Spending	
		Historical	Projected Bridge Period			Projected Test Year		12 Months Ended December 2022	
Line No.	Description	12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	Reference	Authorized U-21297	Actual 2022 Higher/(Lower)
					col. (c)+(d)				
1	Production Plant:								
2	Steam	323,045	372,353	362,878	735,232	115,848	Exh. A-12, Sch. B5.1	313,818	9,227
3	Hydraulic	22,957	12,004	8,775	20,779	10,800	Exh. A-12, Sch. B5.1	22,216	741
4	Other	113,387	69,840	216,747	286,587	333,706	Exh. A-12, Sch. B5.1	111,100	2,287
5	MERC / Fuel Supply	2,224	1,626	1,290	2,916	1,154	Exh. A-12, Sch. B5.2	-	2,224
6	Nuclear (including Nuclear Fuel)	257,759	266,703	184,765	451,468	215,947	Exh. A-12, Sch. B5.3	258,748	(989)
7	Distribution	1,496,136	1,633,201	1,504,572	3,137,772	1,634,979	Exh. A-12, Sch. B5.4	1,434,336	61,800
8	Community Lighting	17,820	16,700	16,700	33,400	17,300	Exh. A-12, Sch. B5.5	17,250	570
9	Demand Side Management	9,400	10,675	8,075	18,750	6,000	Exh. A-12, Sch. B5.6	7,586	1,814
10	Information Technology	224,295	162,310	152,281	314,591	145,653	Exh. A-12, Sch. B5.7	164,963	59,332
11	Corporate Staff	126,597	138,881	96,968	235,849	120,080	Exh. A-12, Sch. B5.8	127,109	(512)
12	Charging Forward	15	994	12,509	13,503	5,100	Exh. A-12, Sch. B5.9	1	14
13	Total Capital Expenditures	2,593,634	2,685,288	2,565,561	5,250,849	2,606,566		2,457,127	136,507

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Breakout of Removal Costs and Additions
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5
Witness: T. M. Uzenski
Page: 2 of 4

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	Projected Bridge Period			Projected Test Year	Reference
		12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
				col. (b)+(c)		
	TOTAL CAPITAL EXPENDITURES					
1	Production Plant:					
2	Steam	372,353	362,878	735,232	115,848	Exh. A-12, Sch. B5.1
3	Hydraulic	12,004	8,775	20,779	10,800	Exh. A-12, Sch. B5.1
4	Other	69,840	216,747	286,587	333,706	Exh. A-12, Sch. B5.1
5	MERC / Fuel Supply	1,626	1,290	2,916	1,154	Exh. A-12, Sch. B5.2
6	Nuclear (including Nuclear Fuel)	266,703	184,765	451,468	215,947	Exh. A-12, Sch. B5.3
7	Distribution	1,633,201	1,504,572	3,137,772	1,634,979	Exh. A-12, Sch. B5.4
8	Community Lighting	16,700	16,700	33,400	17,300	Exh. A-12, Sch. B5.5
9	Demand Side Management	10,675	8,075	18,750	6,000	Exh. A-12, Sch. B5.6
10	Information Technology	162,310	152,281	314,591	145,653	Exh. A-12, Sch. B5.7
11	Corporate Staff	138,881	96,968	235,849	120,080	Exh. A-12, Sch. B5.8
12	Charging Forward	994	12,509	13,503	5,100	Exh. A-12, Sch. B5.9
13	Total Capital Expenditures per A-12 B5 page 1	2,685,288	2,565,561	5,250,849	2,606,566	
14	ESTIMATED REMOVAL COSTS 1/					
15	Production Plant:					
16	Steam	100,803	74,853	175,656	25,698	Exh. A-12, Sch. B5.1
17	Hydraulic	1,574	1,316	2,891	1,620	Exh. A-12, Sch. B5.1
18	Other	7,360	8,430	15,790	6,251	Exh. A-12, Sch. B5.1
19	MERC / Fuel Supply	244	194	437	173	Exh. A-12, Sch. B5 (pp. 3-4)
20	Nuclear	22,342	26,282	48,623	12,021	Exh. A-12, Sch. B5.3
21	Distribution	220,139	207,398	427,537	209,911	Exh. A-12, Sch. B5.4
22	Community Lighting	2,505	2,505	5,010	2,595	Exh. A-12, Sch. B5 (pp. 3-4)
23	Demand Side Management	-	-	-	-	Exh. A-12, Sch. B5 (pp. 3-4)
24	Information Technology	-	-	-	-	Exh. A-12, Sch. B5 (pp. 3-4)
25	Corporate Staff	9,007	3,567	12,573	4,721	Exh. A-12, Sch. B5.8
26	Charging Forward	-	-	-	-	Exh. A-12, Sch. B5 (pp. 3-4)
27	Total Capital Expenditures-Removal Costs	363,974	324,544	688,518	262,991	
28	ESTIMATED EXPENDITURES IN CWIP/PLANT 2/					
29	Production Plant:					
30	Steam	271,550	288,025	559,576	90,149	Line 2 - Line 16
31	Hydraulic	10,430	7,459	17,889	9,180	Line 3 - Line 17
32	Other	62,480	208,317	270,797	327,454	Line 4 - Line 18
33	MERC / Fuel Supply	1,382	1,097	2,479	981	Line 5 - Line 19
34	Nuclear (including Nuclear Fuel)	244,361	158,483	402,844	203,926	Line 6 - Line 20
35	Distribution	1,413,061	1,297,174	2,710,235	1,425,068	Line 7 - Line 21
36	Community Lighting	14,195	14,195	28,390	14,705	Line 8 - Line 22
37	Demand Side Management	10,675	8,075	18,750	6,000	Line 9 - Line 23
38	Information Technology	162,310	152,281	314,591	145,653	Line 10 - Line 24
39	Corporate Staff	129,874	93,402	223,276	115,358	Line 11 - Line 25
40	Charging Forward	994	12,509	13,503	5,100	Line 12 - Line 26
41	Total Capital Expenditures - CWIP/Plant	2,321,314	2,241,017	4,562,330	2,343,575	

1/ Plant removal costs are debited to Accumulated Depreciation
2/ Initially debited to CWIP and moved to Gross Plant when placed in service

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5
Witness: T. M. Uzenski
Page: 3 of 4

Company Summary

Line No.	(a) Description	(b) Reference	(c) Plant Classification	(d) Capital Expenditures (including Removal Costs, net of Salvage) 12 mos. ending 12/31/2023	(e) 12 mos. ending 12/31/2024	(f) 12 mos. ending 12/31/2025	(g) Activity Accum. Depr. - Removal Costs 12 mos. ending 12/31/2023	(h) 12 mos. ending 12/31/2024	(i) 12 mos. ending 12/31/2025
1	Steam Power Generation								
2	Routine								
3	Steam Power-Monroe (Investment)	Exh. A-12, Sch. B5.1	Production Plant, Steam Monroe	136,743	105,557	-	-	-	-
4	Steam Power-Monroe (Removal)	Exh. A-12, Sch. B5.1	Production Plant, Steam Other	24,131	18,628	-	24,131	18,628	-
5	Steam Power-Other	Exh. A-12, Sch. B5.1	Production Plant, Steam Other	55,510	86,692	61,944	8,327	13,004	9,292
6	Hydraulic Power	Exh. A-12, Sch. B5.1	Production Plant, Hydraulic	10,496	8,775	10,800	1,574	1,316	1,620
7	Other Production	Exh. A-12, Sch. B5.1	Production Plant, Other	47,109	54,126	41,677	7,066	8,119	6,251
8	Non-Routine								
9	Removal - Monroe Steam Plant	Exh. A-12, Sch. B5.1	Production Plant, Steam Other	19,137	16,871	-	19,137	16,871	-
10	Removal - Other Steam Plant	Exh. A-12, Sch. B5.1	Production Plant, Steam Other	92,476	61,849	16,407	92,476	61,849	16,407
11	Environmental & Other - Monroe	Exh. A-12, Sch. B5.1	Production Plant, Steam Monroe	32,666	28,294	(4,261)	-	-	-
12	Environmental & Other - Other Steam	Exh. A-12, Sch. B5.1	Production Plant, Steam Other	11,690	44,987	41,758	-	-	-
13	Hydraulic Power	Exh. A-12, Sch. B5.1	Production Plant, Hydraulic	1,508	-	-	-	-	-
14	Other Production	Exh. A-12, Sch. B5.1	Production Plant, Other	22,730	162,621	292,029	294	312	-
15				454,198	588,401	460,353	153,006	120,098	33,570
16	Nuclear Generation								
17	Routine	Exh. A-12, Sch. B5.3	Production Plant, Nuclear	66,265	68,892	42,450	9,940	10,334	6,368
18	Non-Routine	Exh. A-12, Sch. B5.3	Production Plant, Nuclear	82,680	106,318	37,690	12,402	15,948	5,654
19	Fermi 2 License	Exh. A-12, Sch. B5.3	Intangible Plant, 20 year	-	-	-	-	-	-
20				148,945	175,211	80,141	22,342	26,282	12,021
21	Distribution Plant								
22	Emergent Replacements	Exh. A-12, Sch. B5.4	Distribution Plant	531,257	492,578	506,851	79,689	73,887	76,028
23	Connections	Exh. A-12, Sch. B5.4	Distribution Plant	300,918	303,216	300,848	45,138	45,482	45,127
24	Infrastructure Resilience	Exh. A-12, Sch. B5.4	Distribution Plant	376,177	295,363	364,706	56,427	44,304	54,706
25	Infrastructure Redesign	Exh. A-12, Sch. B5.4	Distribution Plant	259,244	291,496	227,003	38,887	43,724	34,050
26	Technology and Automation-ADMS	Exh. A-12, Sch. B5.4	Intangible Plant, 15 year	11,269	1,600	2,800	-	-	-
27	Technology and Automation-Other	Exh. A-12, Sch. B5.4	Distribution Plant	154,336	120,319	232,771	-	-	-
28				1,633,201	1,504,572	1,634,979	220,139	207,398	209,911
29	Corporate Staff								
30	Intangible Plant, 5 year	Exh. A-12, Sch. B5.8	Intangible Plant, 5 year	-	-	-	-	-	-
31	General Plant, Depreciable	Exh. A-12, Sch. B5.8	General Plant, Depreciable	138,881	96,968	120,080	9,007	3,567	4,721
32				138,881	96,968	120,080	9,007	3,567	4,721
33	Information Technology								
34	Routine IT Expenditures	B5.7 Support	General Plant, Computer Equip 5 yr	55,855	51,221	50,275	0%	-	-
35	Routine IT Expenditures	B5.7 Support	Intangible Plant, 5 year	99,298	91,060	89,378	0%	-	-
36	Large System Projects	B5.7 Support	General Plant, Depreciable	2,577	3,600	2,160	0%	-	-
37	Large System Projects	B5.7 Support	Intangible Plant, 15 year	4,581	6,400	3,840	0%	-	-
38				162,310	152,281	145,653	-	-	-
39	Other								
40	MERC and Fuel Supply	Exh. A-12, Sch. B5.2	Production Plant, MERC	1,626	1,290	1,154	15%	244	194
41	Community Lighting	Exh. A-12, Sch. B5.5	Distribution Plant	16,700	16,700	17,300	15%	2,505	2,505
42	Demand Side Management	Exh. A-12, Sch. B5.6	General Plant, Computer Equip 5 yr	10,675	8,075	6,000	0%	-	-
43	Charging Forward	Exh. A-12, Sch. B5.9	Distribution Plant	994	12,509	5,100	0%	-	-
44				29,995	38,574	29,554	2,749	2,698	2,768
45	Total Utility Plant			2,567,530	2,556,007	2,470,760	407,243	360,043	262,991
46	Fermi 2 License Renewal	Exh. A-12, Sch. B5.3	Held for Future Use	7,750	7,554	729	-	-	-
47	Nuclear Fuel	Exh. A-12, Sch. B5.3	Nuclear Fuel	110,008	2,000	135,077	-	-	-
48	Total Capital Expenditures			2,685,288	2,565,561	2,606,566	407,243	360,043	262,991

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
(\$000)

Case No.: U-21534
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Witness: T. M. Uzenski
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Company Summary (continued)

Line No.	(a) Description	(j)			(m)		
		(k) Activity Plant in Service			(n) Activity CWIP - Net Additions/(Unitization)		
		12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025
					<i>col (d)-(g)-(j)</i>	<i>col (e)-(h)-(k)</i>	<i>col (f)-(i)-(l)</i>
					<i>column references refer to pages 3 and 4</i>		
1	Steam Power Generation						
2	Routine						
3	Steam Power-Monroe (Investment)	136,743	105,557	-	-	-	-
4	Steam Power-Monroe (Removal)	-	-	-	-	-	-
5	Steam Power-Other	47,184	73,688	52,652	-	-	-
6	Hydraulic Power	8,922	7,459	9,180	-	-	-
7	Other Production	40,043	46,007	35,425	-	-	-
8	Non-Routine						
9	Removal - Monroe Steam Plant	-	-	-	-	-	-
10	Removal - Other Steam Plant	-	-	-	-	-	-
11	Environmental & Other - Monroe	32,666	28,294	(4,261)	-	-	-
12	Environmental & Other - Other Steam	11,690	44,987	41,758	-	-	-
13	Hydraulic Power	1,508	-	-	-	-	-
14	Other Production	(9,331)	97,544	129	31,768	64,766	291,900
15		269,424	403,537	134,884	31,768	64,766	291,900
16	Nuclear Generation						
17	Routine	56,325	58,559	36,083	-	-	-
18	Non-Routine	4,023	97,433	10,044	66,255	(7,063)	21,993
19	Fermi 2 License	-	-	-	-	-	-
20		60,348	155,992	46,127	66,255	(7,063)	21,993
21	Distribution Plant						
22	Emergent Replacements	451,569	418,691	430,823	-	-	-
23	Connections	250,733	236,484	282,018	5,047	21,250	(26,297)
24	Infrastructure Resilience	318,822	265,690	309,599	928	(14,631)	401
25	Infrastructure Redesign	51,153	137,753	230,955	169,205	110,018	(38,003)
26	Technology and Automation-ADMS	38,231	-	-	(26,963)	1,600	2,800
27	Technology and Automation-Other	62,373	117,931	171,036	91,964	2,389	61,735
28		1,172,880	1,176,548	1,424,432	240,181	120,625	636
29	Corporate Staff						
30	Intangible Plant, 5 year	-	-	-	-	-	-
31	General Plant, Depreciable	94,476	128,711	124,869	35,398	(35,310)	(9,510)
32		94,476	128,711	124,869	35,398	(35,310)	(9,510)
33	Information Technology						
34	Routine IT Expenditures	55,317	51,221	50,275	537	-	-
35	Routine IT Expenditures	98,342	91,060	89,378	955	-	-
36	Large System Projects	(303)	3,600	8,657	2,880	-	(6,497)
37	Large System Projects	(539)	6,400	15,389	5,120	-	(11,549)
38		152,817	152,281	163,699	9,493	-	(18,046)
39	Other						
40	MERC and Fuel Supply	1,382	1,097	981	-	-	-
41	Community Lighting	14,195	14,195	14,705	-	-	-
42	Demand Side Management	10,675	8,075	6,000	-	-	-
43	Charging Forward	994	12,509	5,100	-	-	-
44		27,246	35,876	26,786	-	-	-
45	Total Utility Plant	1,777,192	2,052,946	1,920,796	383,095	143,018	286,973
46	Fermi 2 License Renewal	-	-	-	7,750	7,554	729
47	Nuclear Fuel	110,008	2,000	135,077	-	-	-
48	Total Capital Expenditures	1,887,200	2,054,946	2,055,872	390,845	150,572	287,702

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Steam, Hydraulic, and
Other Power Generation
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.1
Witness: M. E. Guillaumin
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Projected Bridge Period				Projected Test Year	
Line No.	Description	Historical 12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024 <i>col. (c)+(d)</i>	12 mos. ending 12/31/2025	Reference
1	Steam Power Generation						
2	Routine	218,988	216,384	210,877	427,261	61,944	Exh A-12, B5.1 page 3
3	Non-Routine	104,057	155,969	152,002	307,971	53,904	Exh A-12, B5.1 page 2
4	Total Steam Power Generation	323,045	372,353	362,878	735,232	115,848	
5	Hydraulic Power Generation						
6	Routine	12,978	10,496	8,775	19,271	10,800	Exh A-12, B5.1 page 3
7	Non-Routine	9,979	1,508	-	1,508	-	Exh A-12, B5.1 page 2
8	Total Hydraulic Power Generation	22,957	12,004	8,775	20,779	10,800	
9	Other Power Generation						
10	Routine	66,684	47,109	54,126	101,236	41,677	Exh A-12, B5.1 page 3
11	Non-Routine	46,703	22,730	162,621	185,352	292,029	Exh A-12, B5.1 page 2
12	Total Other Power Generation	113,387	69,840	216,747	286,587	333,706	
13	Grand Total Capital Expenditures	459,389	454,198	588,401	1,042,598	460,353	
14	Monroe Regulatory Asset Expenditures						
15	Routine	-	-	-	-	77,968	Exh A-12, B5.1 page 3
16	Non-Routine	-	-	-	-	49,136	Exh A-12, B5.1 page 2
17	Total Monroe Regulatory Asset	-	-	-	-	127,104	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Steam, Hydraulic, and
Other Power Generation -- Non-Routine
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.1
Witness: M. E. Guillaumin
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period		Projected Test Year		
Line No.	Description	12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	In Service Year
					col. (c)+(d)		
1	Steam Power Generation - Non-Routine Additions:						
2	Belle River Fuel Conversion	1,419	2,244	39,299	41,543	41,758	Annual
3	Belle River Bottom Ash Basin Modification (CCR)	60	3,363	-	3,363	-	Annual
4	Monroe Dry Fly Ash Conversion (ELG)	19,998	20,830	1,200	22,030	-	Annual
5	Monroe Bottom Ash Conversion (ELG)	4,191	11,357	26,095	37,451	(4,261)	Annual
6	Monroe FGD Wastewater (ELG)	339	479	1,000	1,479	-	Annual
7	Monroe Dry Fly Ash Haul Road	313	-	-	-	-	Annual
8	Site Security Project 11504	2,789	2,155	5,383	7,538	-	Annual
9	Site Security Project 18700	15	52	-	52	-	Annual
10	Site Security Project 18906	1	765	298	1,063	-	Annual
11	Site Security Project 20061	-	182	-	182	-	Annual
12	NERC Compliance Project 18885	648	1,076	-	1,076	-	Annual
13	NERC Compliance Project 19895	-	7	-	7	-	Annual
14	Sibley Quarry Landfill Modification (CCR)	5,575	1,804	8	1,812	-	Annual
15	Sibley Quarry Conveyor Installation (CCR)	382	-	-	-	-	Annual
16	Sibley Quarry Infrastructure Modification (CCR)	1,791	9	-	9	-	Annual
17	Sibley Quarry Landfill Dewatering and Discharging Line	1,754	32	-	32	-	Annual
18	Total Steam Power Generation - Non-Routine	39,275	44,356	73,281	117,637	37,497	
19	Steam Power Generation - Non-Routine Removals:						
20	Monroe Bottom Ash Basin Closure (CCR)	15,393	14,637	11,871	26,508	-	Annual
21	Monroe Fly Ash Basin Closure (CCR)	528	4,500	5,000	9,500	-	Annual
22	St. Clair Bottom Ash Basin Closure (CCR)	7,933	405	-	405	-	Annual
23	Harbor Beach Decommissioning	17	-	-	-	-	Annual
24	Connors Creek Sea Wall	8,073	-	-	-	-	Annual
25	River Rouge Decommissioning	12,955	21,148	12,808	33,956	-	Annual
26	St Clair Decommissioning	9,918	21,863	13,000	34,863	-	Annual
27	Trenton Channel Decommissioning	9,965	48,675	35,000	83,675	6,900	Annual
28	Trenton Channel Sea Wall	-	386	1,041	1,427	9,507	Annual
29	Steam Power Generation - Non-Routine Removals - TOTAL	64,782	111,614	78,720	190,334	16,407	
30	Steam Power Generation - Non-Routine - TOTALS	104,057	155,969	152,002	307,971	53,904	
31	Hydraulic Power Generation - Non-Routine:						
32	Ludington Upgrades	9,979	1,508	-	1,508	-	Annual
33	Hydraulic Power Generation - Non-Routine - TOTALS	9,979	1,508	-	1,508	-	
34	Other Power Generation - Non-Routine:						
35	Blue Water Energy Center (CCGT)	11,777	(4,512)	6,000	1,489	-	Annual
36	BWEC Transmission Upgrades	5,506	(4,819)	-	(4,819)	-	2022
37	Blackstart Project 10570 & 20255	20,743	10,390	2,243	12,633	-	2024
38	Blackstart Project 17611	53	2,013	6,089	8,102	-	2024
39	Blackstart Project 18320	1,063	4,000	445	4,445	-	2024
40	Slocum Battery Pilot	7,562	10,111	26,832	36,943	129	2024
41	Trenton Channel Energy Center BESS	0	5,253	120,700	125,953	291,900	2026
42	Northeast 11-1 Decommissioning	-	294	312	605	-	2025
43	Other Power Generation - Non-Routine - TOTALS	46,703	22,730	162,621	185,352	292,029	
44	TOTAL NON-ROUTINE CAPITAL EXPENDITURES	160,740	180,208	314,623	494,831	345,933	
45							
46	Monroe Regulatory Asset effective January 2025 :						
47	Monroe Bottom Ash Conversion (ELG)	-	-	-	-	23,136	
48	Monroe FGD Wastewater (ELG)	-	-	-	-	1,000	
49	Monroe Fly Ash Basin Closure (CCR)	-	-	-	-	25,000	
50	TOTAL NON-ROUTINE REG ASSET EXPENDITURES	-	-	-	-	49,136	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Steam, Hydraulic, and
Other Power Generation -- Routine
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.1
Witness: M. E. Guillaumin
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	(a)	(b)	(c)	(d)	(e)	(f)
	Capital Expenditures					
	Historical	Projected Bridge Period			Projected Test Year	
Line	12 mos. ended	12 mos. ending	12 mos. ending	24 mos. ending	12 mos. ending	
No.	Total Capital - Routine	12/31/2022	12/31/2023	12/31/2024	12/31/2024	12/31/2025
	DATA BY SITE				<i>col. (c)+(d)</i>	
1	Fleet Support Services	3,085	2,115	609	2,724	507
2	Greenwood	10,581	10,125	18,817	28,941	18,680
3	Belle River/Range Road	59,478	33,670	58,950	92,619	42,757
4	St. Clair	(2)	-	-	-	-
5	Trenton Channel/Sibley Quarry	614	9,601	8,317	17,918	-
6	Monroe	145,233	160,874	124,185	285,059	-
7	Subtotal - Steam Power Generation	218,988	216,384	210,877	427,261	61,944
8	Ludington	12,978	10,496	8,775	19,271	10,800
9	Peakers	65,649	44,402	38,947	83,349	29,743
10	Blue Water	1,035	2,707	15,179	17,886	11,934
11	Subtotal - Other Power Generation	79,662	57,606	62,901	120,507	52,477
12	Total All Sites	298,649	273,990	273,778	547,768	114,421
13	Monroe Regulatory Asset Exp. - effective January 2025	-	-	-	-	77,968
14	Grand Total	298,649	273,990	273,778	547,768	192,389
	DATA BY MAJOR CATEGORY					
13	Reliability/Capital Maintenance	121,708	111,809	105,907	217,716	77,796
14	Fleet Support Services	3,085	2,115	609	2,724	507
15	Safety/Combustible Dust	63,901	66,238	86,691	152,929	54,117
16	Minor Environmental	31,329	38,929	32,850	71,779	19,426
17	Other Power Generation - Ludington	12,978	10,496	8,775	19,271	10,800
18	Other Power Generation - Peakers	65,649	44,402	38,947	83,349	29,743
19	Total - All Major Categories	298,649	273,990	273,778	547,768	192,389

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Years 2022 to 2025
Routine Maintenance Projects greater than \$1M

Case No.: U-21534
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Line No.	(a) Facility	(b) Calendar Year	(c) Unit	(d) High Level Breakdown	(f) Description	(h) Amount
1	Belle River/Range Road	2022	1	Safety	Unit 1 LP Turbine Rotor & Blades	5,405,489
2	Belle River/Range Road	2022	1	Safety	Unit 1 HP & IP Turbine Valve Actuators	4,030,720
3	Belle River/Range Road	2022	1	Reliability	Unit 1 Waterwall Tubes	3,772,167
4	Belle River/Range Road	2022	1	Reliability	Unit 1 HP Turbine Blades	3,419,231
5	Belle River/Range Road	2022	1	Reliability	Unit 1 Intake Underground Line Cables	2,752,655
6	Belle River/Range Road	2022	1	Safety	Unit 1 Ignitor System	2,229,962
7	Belle River/Range Road	2022	1	Safety	Unit 1 HP Turbine Valves	2,076,973
8	Belle River/Range Road	2022	1	Reliability	Unit 1 Primary Air Heater Baskets	2,007,061
9	Belle River/Range Road	2022	1	Reliability	Unit 1 Horizontal Middle Reheater Tubes	1,444,070
10	Belle River/Range Road	2022	1	Reliability	Unit 1 Generator Phase Bushings	1,221,579
11	Belle River/Range Road	2022	1	Reliability	Unit 1 Purple Coal Mill	1,122,830
12	Belle River/Range Road	2022	1	Reliability	Unit 1 ID Fan	1,041,104
13	Belle River/Range Road	2022	2	Safety	Unit 2 LP Turbine Rotor & Blades	2,856,461
14	Belle River/Range Road	2022	Fuel Supply	Safety	Fuel Supply East Main Coal Pile	2,294,572
15	Belle River/Range Road	2022	Fuel Supply	Reliability	Fuel Supply HMI, DCS, & Control Room	1,796,768
16	Belle River/Range Road	2022	Fuel Supply	Combustible Dust	Fuel Supply Dust Collector 3TH-8	1,683,233
17	Belle River/Range Road	2022	Fuel Supply	Infrastructure	Fuel Supply & Common Systems Separation from St. Clair Power Plant	1,663,317
18	Belle River/Range Road	2022	Fuel Supply	Combustible Dust	Fuel Supply CV2 to CV4 Transfer Chute	1,285,936
19	Greenwood Energy Center	2022	1	Safety	Unit 1 LP Turbine Rotor & Blades	7,579,572
20	Greenwood Energy Center	2022	1	Reliability	Unit 1 North ID Fan	1,010,203
21	Monroe without Large Enviro.	2022	1	Safety	Unit 1 LPA & LPB Turbine Rotor & Blades	9,559,398
22	Monroe without Large Enviro.	2022	1	Minor Environmental	Unit 1 SCR Catalyst Layers 1, 2, & 4	3,996,175
23	Monroe without Large Enviro.	2022	1	Reliability	Unit 1 Waterwall Tubes	3,891,787
24	Monroe without Large Enviro.	2022	1	Reliability	Unit 1 Expansion Joints	2,709,781
25	Monroe without Large Enviro.	2022	1	Reliability	Unit 1 South Air Heater Hot and Cold End Baskets	2,442,461
26	Monroe without Large Enviro.	2022	1	Reliability	Unit 1 Reheat Outlet Pendants	1,608,776
27	Monroe without Large Enviro.	2022	1	Minor Environmental	Unit 1 North & South FGD Booster Fans & Hubs	1,577,743
28	Monroe without Large Enviro.	2022	1	Minor Environmental	Unit 1 FGD Asset Preservation	1,131,629
29	Monroe without Large Enviro.	2022	1	Safety	Unit 1 Coal Mill Primary Air Duct & Damper	1,081,577
30	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 Waterwall Tubes	16,800,778
31	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 IP Turbine Blades	4,320,858
32	Monroe without Large Enviro.	2022	2	Minor Environmental	Unit 2 SCR Catalyst Layers 1, 2, & 4	4,104,961
33	Monroe without Large Enviro.	2022	2	Safety	Unit 2 Coal Mill Primary Air Duct & Damper	3,632,006
34	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 Expansion Joints	2,695,089
35	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 Horizontal Reheater Tubes	2,589,605
36	Monroe without Large Enviro.	2022	2	Minor Environmental	Unit 2 FGD Absorber Inlet Expansion Joint	1,867,223
37	Monroe without Large Enviro.	2022	2	Minor Environmental	Unit 2 North & South FGD Booster Fans & Hubs	1,473,742
38	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 DCS & Control Room	1,260,162
39	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 Coal Mill 2-7 Silo	1,238,034
40	Monroe without Large Enviro.	2022	2	Minor Environmental	Unit 2 FGD Asset Preservation	1,174,165
41	Monroe without Large Enviro.	2022	2	Reliability	Unit 2 Coal Mill 2-1 Silo	1,162,697
42	Monroe without Large Enviro.	2022	2	Minor Environmental	Unit 2 1st and 2nd Stage FGD Mist Eliminators	1,049,325
43	Monroe without Large Enviro.	2022	3	Minor Environmental	Unit 3 SCR Catalyst Layer 1	3,213,706
44	Monroe without Large Enviro.	2022	3	Minor Environmental	Unit 3 1st & 2nd Stage FGD Mist Eliminators	1,609,564
45	Monroe without Large Enviro.	2022	3	Reliability	Unit 3 Coal Mill 3-5 Silo	1,182,156
46	Monroe without Large Enviro.	2022	3	Reliability	Unit 3 Coal Mill 3-6 Silo	1,148,213
47	Monroe without Large Enviro.	2022	4	Reliability	Unit 4 Generator Stator	2,153,641
48	Monroe without Large Enviro.	2022	Common	Reliability	Main Unit Transformer	3,890,944
49	Monroe without Large Enviro.	2022	Fuel Supply	Safety	Fuel Supply Tripper Gallery J Infrastructure	4,071,683
50	Monroe without Large Enviro.	2022	Fuel Supply	Combustible Dust	Fuel Supply CV-04 Transfer Chute	2,825,273
51	Monroe without Large Enviro.	2022	Fuel Supply	Safety	Fuel Supply Tripper Gallery B Infrastructure	1,256,513
52	Monroe without Large Enviro.	2022	Fuel Supply	Minor Environmental	Fuel Supply Coal Pile Runoff Oil Waste Water System	1,097,099
53	Peakers	2022	Belle River	Reliability	Belle River 12-1 Peaker Major Overhaul	6,515,029
54	Peakers	2022	Belle River	Reliability	Belle River 12-2 Peaker Major Overhaul	2,050,121
55	Peakers	2022	Belle River	Reliability	Belle River 12-1 Peaker Generator Field	2,045,770
56	Peakers	2022	Belle River	Reliability	Belle River 13-1 Peaker Combustion Overhaul	1,655,377
57	Peakers	2022	Greenwood	Reliability	Greenwood 12-1 Peaker Combustion Overhaul	1,668,800
58	Peakers	2022	Greenwood	Reliability	Greenwood 11-1 Peaker Combustion Overhaul	1,502,291
59	Peakers	2022	Greenwood	Reliability	Greenwood 11-2 Peaker Combustion Overhaul	1,246,124
60	Peakers	2022	Renaissance	Reliability	Renaissance Unit 4 Peaker Major Overhaul	13,471,981
61	Peakers	2022	Renaissance	Reliability	Renaissance Unit 3 Peaker Major Overhaul	9,690,430
62	Peakers	2022	Renaissance	Reliability	Renaissance Unit 1 Peaker Major Overhaul	7,374,897
63	Peakers	2022	Renaissance	Reliability	Renaissance Unit 3 Peaker Exhaust Cylinder & Manifold	3,648,091
64	Peakers	2022	Renaissance	Minor Environmental	Renaissance Unit 3 Peaker Exhaust Silencers	2,928,869
65	Peakers	2022	Renaissance	Reliability	Renaissance Peakers Main Unit Transformer	2,020,585
66	Peakers	2022	Renaissance	Minor Environmental	Renaissance Unit 4 Peaker Exhaust Silencers	1,293,642
67	Total 2022 Projects					201,622,673

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Years 2022 to 2025
Routine Maintenance Projects greater than \$1M

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	(a)	(b)	(c)	(d)	(f)	(h)
Line No.	Facility	Calendar Year	Unit	High Level Breakdown	Description	Amount
68	Belle River/Range Road	2023	2	Safety	Unit 2 LP Turbine Rotor & Blades	6,144,178
69	Belle River/Range Road	2023	2	Reliability	Unit 2 Exciter	2,310,006
70	Belle River/Range Road	2023	2	Reliability	Unit 2 Waterwall Tubes	1,519,132
71	Belle River/Range Road	2023	2	Safety	Unit 2 IP Turbine Valves	1,491,435
72	Belle River/Range Road	2023	Fuel Supply	Infrastructure	Fuel Supply & Common Systems Separation from St. Clair Power Plant	3,269,462
73	Belle River/Range Road	2023	Fuel Supply	Combustible Dust	Fuel Supply Dust Collector 3TH-9	1,848,837
74	Greenwood Energy Center	2023	1	Safety	Unit 1 LP Turbine Rotor & Blades	5,755,186
75	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Waterwall Tubes	15,036,693
76	Monroe without Large Enviro.	2023	1	Safety	Unit 1 LPA & LPB Turbine Rotor and Blades	10,442,714
77	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Reheat Outlet Pendants	5,403,649
78	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Expansion Joints	5,324,148
79	Monroe without Large Enviro.	2023	1	Safety	Unit 1 Coal Mill Primary Air Duct & Damper	4,205,353
80	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 HP Turbine Blades	3,855,918
81	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 IP Turbine Blades	3,745,394
82	Monroe without Large Enviro.	2023	1	Minor Environmental	Unit 1 SCR Catalyst Layers 1, 2, & 4	3,312,499
83	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 IP Turbine Rotor	2,569,158
84	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Economizer Tubes	2,457,650
85	Monroe without Large Enviro.	2023	1	Safety	Unit 1 Reheat Stop Valves	2,394,471
86	Monroe without Large Enviro.	2023	1	Minor Environmental	Unit 1 SCR Inlet & Outlet Dampers	1,480,864
87	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Air Heater Hot and Cold End Baskets	1,430,916
88	Monroe without Large Enviro.	2023	1	Safety	Unit 1 Main Turbine Control Valves	1,321,411
89	Monroe without Large Enviro.	2023	1	Safety	Unit 1 Main Steam Stop Valve	1,261,517
90	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Coal Mill 1-3 Silo	1,181,903
91	Monroe without Large Enviro.	2023	1	Reliability	Unit 1 Turning Gear & Bull Gear	1,159,354
92	Monroe without Large Enviro.	2023	1	Minor Environmental	Unit 1 1st & 2nd Stage FGD Mist Eliminators	1,103,375
93	Monroe without Large Enviro.	2023	1	Minor Environmental	Unit 1 FGD Absorber Inlet Expansion Joint	1,072,714
94	Monroe without Large Enviro.	2023	1	Minor Environmental	Unit 1 North & South FGD Booster Fans & Hubs	1,055,427
95	Monroe without Large Enviro.	2023	2	Reliability	Unit 2 Air Heater Cold End Baskets	1,177,204
96	Monroe without Large Enviro.	2023	3	Reliability	Unit 3 Air Heater Cold End Baskets	2,233,362
97	Monroe without Large Enviro.	2023	3	Minor Environmental	Unit 3 SCR Catalyst	1,502,242
98	Monroe without Large Enviro.	2023	3	Reliability	Unit 3 Expansion Joints	1,309,470
99	Monroe without Large Enviro.	2023	3	Safety	Unit 3 Coal Mill Primary Air Duct & Damper	1,138,011
100	Monroe without Large Enviro.	2023	3	Reliability	Unit 3 Coal Mill 3-6 Overhaul	1,025,164
101	Monroe without Large Enviro.	2023	4	Safety	Unit 4 LPA & LPB Turbine Rotor and Blades	4,293,479
102	Monroe without Large Enviro.	2023	4	Minor Environmental	Unit 4 SCR Catalyst Layer 2	2,114,701
103	Monroe without Large Enviro.	2023	4	Reliability	Unit 4 South Boiler Feed Pump Turbine Condenser	1,812,769
104	Monroe without Large Enviro.	2023	4	Minor Environmental	Unit 4 SCR Catalyst Layers 1, 3, & 4	1,541,696
105	Monroe without Large Enviro.	2023	4	Reliability	Unit 4 Coal Mill 4-1 Silo	1,527,037
106	Monroe without Large Enviro.	2023	Common	Reliability	Main Unit Transformer	3,027,239
107	Monroe without Large Enviro.	2023	Common	Minor Environmental	Underground Storage Tank 389	1,985,817
108	Monroe without Large Enviro.	2023	Fuel Supply	Minor Environmental	Fuel Supply Coal Pile Runoff Oil Waste Water System	4,615,508
109	Monroe without Large Enviro.	2023	Fuel Supply	Safety	Fuel Supply Tripper Gallery B Infrastructure	3,004,942
110	Monroe without Large Enviro.	2023	Fuel Supply	Combustible Dust	Fuel Supply CV-C4 to CV-C5 & CV-CV5A Transfer Chute	2,650,339
111	Monroe without Large Enviro.	2023	Fuel Supply	Combustible Dust	Fuel Supply CV-04 Transfer Chute	1,959,127
112	Monroe without Large Enviro.	2023	Fuel Supply	Safety	Fuel Supply Tripper Gallery C Infrastructure	1,710,569
113	Monroe without Large Enviro.	2023	Fuel Supply	Combustible Dust	Fuel Supply CV-19 to CV-10 Transfer Chute	1,542,396
114	Peakers	2023	Belle River	Reliability	Belle River 12-2 Peaker Major Overhaul	5,408,718
115	Peakers	2023	Belle River	Reliability	Belle River 13-1 Peaker Modified Hot Gas Path Overhaul	1,439,432
116	Peakers	2023	Belle River	Reliability	Belle River 12-2 Peaker Generator Field	1,391,482
117	Peakers	2023	Greenwood	Reliability	Greenwood 11-1 Peaker Major Overhaul	1,372,701
118	Peakers	2023	Northeast	Reliability	Northeast 13-2 Peaker Generator Field	1,610,791
119	Peakers	2023	Renaissance	Reliability	Renaissance Unit 4 Peaker Generator Stator & Rotor	9,159,737
120	Peakers	2023	Renaissance	Reliability	Renaissance Unit 3 Peaker Major Overhaul	7,108,498
121	Peakers	2023	Renaissance	Reliability	Renaissance Unit 2 Peaker Modified Hot Gas Path Overhaul	3,675,069
122	Peakers	2023	Renaissance	Minor Environmental	Renaissance Unit 2 Peaker Exhaust Silencers	2,294,591
123	Peakers	2023	Renaissance	Reliability	Renaissance Unit 3 Peaker Exhaust Cylinder & Manifold	1,796,281
124	Peakers	2023	Renaissance	Minor Environmental	Renaissance Unit 4 Peaker Exhaust Silencers	1,695,382
125	Peakers	2023	Renaissance	Reliability	Renaissance Peakers Main Unit Transformer	1,212,507
126	Trenton Channel	2023	Sibley	Minor Environmental	Sibley Quarry Capping Section 1A	9,600,849
127	Total 2023 Projects					180,090,471

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Years 2022 to 2025
Routine Maintenance Projects greater than \$1M

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	(a)	(b)	(c)	(d)	(f)	(h)	
Line No.	Facility	Calendar Year	Unit	High Level Breakdown	Description	Amount	
128	Belle River/Range Road	2024	1	Safety	Unit 1 480 Volt Breakers	1,959,091	
129	Belle River/Range Road	2024	1	Safety	Unit 1 Medium Voltage Breakers	1,885,436	
130	Belle River/Range Road	2024	1	Reliability	Unit 1 East Boiler Feed Pump Turbine Blades & Rotor	1,299,095	
131	Belle River/Range Road	2024	1	Reliability	Unit 1 White Coal Mill	1,115,254	
132	Belle River/Range Road	2024	2	Safety	Unit 2 LP Turbine Rotor & Blades	6,393,003	
133	Belle River/Range Road	2024	2	Reliability	Unit 2 Waterwall Tubes	4,275,413	
134	Belle River/Range Road	2024	2	Reliability	Unit 2 Exciter	3,333,232	
135	Belle River/Range Road	2024	2	Safety	Unit 2 IP Turbine Valves	2,761,475	
136	Belle River/Range Road	2024	2	Safety	Unit 2 Turbine Stop Valve Actuators	2,667,773	
137	Belle River/Range Road	2024	2	Safety	Unit 2 480 Voltage Breakers	1,956,791	
138	Belle River/Range Road	2024	2	Safety	Unit 2 Medium Voltage Breakers	1,806,959	
139	Belle River/Range Road	2024	2	Reliability	Unit 2 Primary Superheat Tubes	1,669,471	
140	Belle River/Range Road	2024	Common	Safety	Unit 1 & 2 Common Systems 480 Volt Breakers	2,723,260	
141	Belle River/Range Road	2024	Common	Safety	Unit 1 & 2 Common Systems Medium Voltage Breakers	2,021,894	
142	Belle River/Range Road	2024	Common	Minor Environmental	Underground Storage Tanks 387 and 388	1,870,064	
143	Belle River/Range Road	2024	Common	Minor Environmental	Underground Storage Tank 393	1,844,511	
144	Blue Water Energy Center	2024	Common	Infrastructure	Circulating Water Pumps Enclosure	3,739,150	
145	Blue Water Energy Center	2024	Common	Safety	Conference Room Building	3,275,184	
146	Blue Water Energy Center	2024	Common	Reliability	Control Server	1,499,494	
147	Blue Water Energy Center	2024	ST1	Reliability	STG Transformer	1,099,508	
148	Greenwood Energy Center	2024	1	Safety	Unit 1 LP Turbine Rotor & Blades	12,143,798	
149	Greenwood Energy Center	2024	1	Reliability	Unit 1 Feedwater Heater #6	1,613,604	
150	Greenwood Energy Center	2024	1	Reliability	Unit 1 Feedwater Heater #3	1,448,868	
151	Monroe without Large Enviro.	2024	1	Minor Environmental	Unit 1 SCR Catalyst Layer 3	1,468,285	
152	Monroe without Large Enviro.	2024	1	Reliability	Unit 1 IP Turbine Rotor	1,080,689	
153	Monroe without Large Enviro.	2024	2	Safety	Unit 2 LPA & LPB Turbine Rotor and Blades	8,314,504	
154	Monroe without Large Enviro.	2024	2	Reliability	Unit 2 Air Heater Cold End Baskets	4,151,669	
155	Monroe without Large Enviro.	2024	2	Minor Environmental	Unit 2 SCR Catalyst	3,037,515	
156	Monroe without Large Enviro.	2024	2	Reliability	Unit 2 Coal Mill Feeder Controls	1,530,569	
157	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Waterwall Tubes	12,669,845	
158	Monroe without Large Enviro.	2024	3	Minor Environmental	Unit 3 SCR Catalyst	6,721,675	
159	Monroe without Large Enviro.	2024	3	Safety	Unit 3 Coal Mill Primary Air Duct & Damper	5,273,496	
160	Monroe without Large Enviro.	2024	3	Safety	Unit 3 Turbine Valves	4,951,555	
161	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 IP Turbine Blades	4,265,207	
162	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Expansion Joints	3,284,039	
163	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Reheat Outlet Pendants	2,746,985	
164	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Air Heater Cold End Baskets	2,665,273	
165	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Horizontal Reheater Tubes	2,646,409	
166	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 DCS & Control Room	2,577,641	
167	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Coal Mill Classifiers	2,431,044	
168	Monroe without Large Enviro.	2024	3	Reliability	Unit 3 Coal Mill 3-7 Silo	1,545,600	
169	Monroe without Large Enviro.	2024	4	Safety	Unit 4 LPA & LPB Turbine Rotor and Blades	5,993,243	
170	Monroe without Large Enviro.	2024	4	Minor Environmental	Unit 4 SCR Catalyst	3,845,063	
171	Monroe without Large Enviro.	2024	4	Safety	Unit 4 Coal Mill Primary Air Duct & Damper	1,844,952	
172	Monroe without Large Enviro.	2024	4	Reliability	Unit 4 Expansion Joints	1,430,584	
173	Monroe without Large Enviro.	2024	4	Safety	Unit 4 Turbine Valves	1,160,758	
174	Monroe without Large Enviro.	2024	Common	Minor Environmental	Underground Storage Tank 389	1,217,747	
175	Monroe without Large Enviro.	2024	Fuel Supply	Safety	Fuel Supply Tripper Gallery C Infrastructure	4,692,279	
176	Monroe without Large Enviro.	2024	Fuel Supply	Combustible Dust	Fuel Supply CV-C2 Loading Zone Transfer Chutes	2,961,836	
177	Monroe without Large Enviro.	2024	Fuel Supply	Minor Environmental	Fuel Supply Coal Pile Runoff Oil Waste Water System	2,643,109	
178	Peakers	2024	Belle River	Reliability	Belle River 13-1 Peaker Combustion Overhaul	1,435,581	
179	Peakers	2024	DTE	Reliability	Blackstart Peaker Unit 1 Starting System	2,833,435	
180	Peakers	2024	Greenwood	Reliability	Greenwood 11-1 Peaker Major Overhaul	6,814,253	
181	Peakers	2024	Greenwood	Minor Environmental	Greenwood 11-1, 11-2 & 12-1 Peakers Exhaust Silencers	2,928,551	
182	Peakers	2024	Greenwood	Reliability	Greenwood 11-1 Peaker Generator Field	1,703,476	
183	Peakers	2024	Renaissance	Reliability	Renaissance Unit 1 Peaker Generator Stator & Rotor	7,430,660	
184	Peakers	2024	Renaissance	Reliability	Renaissance Unit 3 Peaker Generator Stator Rewind & Rotor	7,035,897	
185	Peakers	2024	Renaissance	Reliability	Renaissance Unit 1 Peaker Main Unit Transformer	1,734,813	
186	Trenton Channel	2024	Sibley	Minor Environmental	Sibley Quarry Capping Section 1A	8,317,276	
187	Total 2024 Projects						201,787,843

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Years 2022 to 2025
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(a)	(b)	(c)	(d)	(f)	(h)
Line No.	Facility	Test Year	Unit	High Level Breakdown Description	Amount
188	Belle River/Range Road	2025	1	Reliability Unit 1 Waterwall Tubes	6,347,145
189	Belle River/Range Road	2025	1	Reliability Unit 1 Secondary Air Heater Baskets	5,288,096
190	Belle River/Range Road	2025	1	Safety Unit 1 IP Turbine Valves	4,475,894
191	Belle River/Range Road	2025	1	Reliability Unit 1 Duplex Heater	3,258,602
192	Belle River/Range Road	2025	1	Reliability Unit 1 Expansion Joints	2,607,260
193	Belle River/Range Road	2025	1	Reliability Unit 1 Horizontal Middle Reheat Tubes	2,197,608
194	Belle River/Range Road	2025	1	Reliability Unit 1 East Boiler Feed Pump Turbine Blades & Rotor	2,392,484
195	Belle River/Range Road	2025	Common	Minor Environmental Range Road Landfill Capping (Area G2 Phase II)	5,022,703
196	Belle River/Range Road	2025	Common	Safety North Auxiliary Boiler	1,869,086
197	Belle River/Range Road	2025	Common	Safety South Auxiliary Boiler	1,866,836
198	Blue Water Energy Center	2025	ST1	Reliability STG Transformer	1,900,068
199	Blue Water Energy Center	2025	Common	Reliability CT Transformer	1,798,256
200	Blue Water Energy Center	2025	Common	Reliability Control Server	1,701,212
201	Greenwood Energy Center	2025	1	Safety Unit 1 LP Turbine Rotor & Blades	5,863,594
202	Greenwood Energy Center	2025	1	Reliability Unit 1 Feedwater Heater #6	2,225,303
203	Greenwood Energy Center	2025	1	Reliability Unit 1 Feedwater Heater #3	2,117,684
204	Greenwood Energy Center	2025	1	Safety Unit 1 Turbine Valves	1,765,657
205	Greenwood Energy Center	2025	1	Reliability Unit 1 North Boiler Feed Pump Turbine Blades	1,508,890
206	Greenwood Energy Center	2025	1	Minor Environmental Underground Storage Tank 377	1,310,838
207	Monroe without Large Enviro.	2025	1	Reliability Unit 1 IP Turbine Rotor	4,167,682
208	Monroe without Large Enviro.	2025	1	Minor Environmental Unit 1 SCR Catalyst Layer 3	2,530,867
209	Monroe without Large Enviro.	2025	1	Reliability Unit 1 Coal Mill Feeder Controls	1,363,072
210	Monroe without Large Enviro.	2025	2	Safety Unit 2 LPA & LPB Turbine Rotor and Blades	10,976,839
211	Monroe without Large Enviro.	2025	2	Minor Environmental Unit 2 SCR Catalyst Layers 1, 2, & 4	4,399,643
212	Monroe without Large Enviro.	2025	2	Reliability Unit 2 North & South Air Heater Hot End Baskets	2,993,448
213	Monroe without Large Enviro.	2025	4	Safety Unit 4 LPA & LPB Turbine Rotor and Blades	5,257,264
214	Monroe without Large Enviro.	2025	4	Safety Unit 4 Turbine Valves	4,194,728
215	Monroe without Large Enviro.	2025	4	Minor Environmental Unit 4 SCR Catalyst Layers 1, 3, & 4	3,588,903
216	Monroe without Large Enviro.	2025	4	Safety Unit 4 Coal Mill Primary Air Duct & Damper	2,649,721
217	Monroe without Large Enviro.	2025	4	Reliability Unit 4 Expansion Joints	2,381,698
218	Monroe without Large Enviro.	2025	4	Minor Environmental Unit 4 FGD Inlet Expansion Joint Flange Mod & Joint	2,054,274
219	Monroe without Large Enviro.	2025	4	Reliability Unit 4 DCS & Control Room	1,914,456
220	Monroe without Large Enviro.	2025	4	Reliability Unit 4 Secondary Heat Exchanger	1,906,379
221	Monroe without Large Enviro.	2025	Common	Reliability U2A Emergency Reactor Cooling & GSW Return Piping	1,038,478
222	Monroe without Large Enviro.	2025	Common	Reliability U2A Reactor Condensate Return	1,032,462
223	Monroe without Large Enviro.	2025	Fuel Supply	Safety Fuel Supply Tripper Gallery D Infrastructure	7,134,048
224	Monroe without Large Enviro.	2025	Fuel Supply	Safety Fuel Supply Dust Collector 04	1,900,054
225	Peakers	2025	DTE	Reliability Blackstart Peaker Unit 2 Starting System	2,794,791
226	Peakers	2025	Delray	Minor Environmental Delray 11-1 & 12-1 Peaker Exhaust Silencers	1,894,035
227	Peakers	2025	Greenwood	Reliability Greenwood 11-2 Peaker Major Overhaul	1,179,132
228	Peakers	2025	Greenwood	Reliability Greenwood 12-1 Peaker Major Overhaul	1,137,038
229	Peakers	2025	Renaissance	Reliability Renaissance 4 Peaker Exhaust Cylinder & Manifold	8,658,508
230	Peakers	2025	Renaissance	Reliability Renaissance Unit 2 Peaker Generator Rotor	3,214,388
231	Peakers	2025	DTE	Reliability Blackstart Unit Major Overhaul	6,376,480
232	Total 2025 Projects				142,255,604

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Steam, Hydraulic, and Other Power Generation
(\$000)

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(a)		(b)	(c)
Line No.	Description	Adjusted Historical 12 mos. ended 12/31/2022	Projected 12 mos. ending 12/31/2025
1	Energy Supply - Routine Expenditures 1/	<u>4,131</u>	<u>1,625</u>
2	Energy Supply - Project Specific:		
3	Ludington	738	-
4	Blue Water Energy Center	896	-
5	Belle River Fuel Conversion	-	2,643
6	Blackstart Project 10570 & 20255	170	-
7	Blackstart Project 17611	1	-
8	Blackstart Project 18320	13	-
9	Site Security Project 11504	68	-
10	Site Security Project 18906	0	-
11	NERC Compliance Project 18885	3	-
12	Slocum Battery	39	-
13	Trenton Channel BESS	-	16,756
14	Subtotal Project Specific	<u>1,928</u>	<u>19,399</u>
15			
16	Total AFUDC - Energy Supply 2/	<u>6,058</u>	<u>21,023</u>

1/ AFUDC estimates for routine projects are developed at a high level based on historical trend

2/ The projected AFUDC amounts are based on the authorized U-21297 of 5.561%

Michigan Public Service Commission DTE Electric Company Projected Capital Expenditures Removal Costs, Plant in Service and CWIP Steam, Hydraulic & Other Power Generation (\$000)													Case No.: U-21534 Exhibit: A-12 Schedule: B5.1 Witness: M. E. Guillaumin Page: 9 of 9			
Line No.	(a) Description	(b) In-Service Assumption	(c)	(d) Capital Expenditures (including Removal Costs)	(e)	(f)	(g) Est. % Removal	(h)	(i) Activity Accum. Depr. - Removal Costs	(j)	(k)	(l) Activity Plant in Service	(m)	(n)	(o) Activity CWIP - Net Additions/(Unitization)	(p)
			12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025		12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025
								col (d)x(g)	col (e)x(g)	col (f)x(g)				col (d)-(h)-(k)	col (e)-(i)-(l)	col (f)-(j)-(m)
1	Routine															
2	Steam Power Gen-Monroe	Annual	145,233	160,874	124,185	-	15%	24,131	18,628	-	136,743	105,557	-	-	-	-
3	Steam Power Gen-Other	Annual	73,755	55,510	86,692	61,944	15%	8,327	13,004	9,292	47,184	73,688	52,652	-	-	-
4	Ludington	Annual	12,978	10,496	8,775	10,800	15%	1,574	1,316	1,620	8,922	7,459	9,180	-	-	-
5	Peakers	Annual	65,649	44,402	38,947	29,743	15%	6,660	5,842	4,461	37,742	33,105	25,281	-	-	-
6	Blue Water	Annual	1,035	2,707	15,179	11,934	15%	406	2,277	1,790	2,301	12,902	10,144	-	-	-
7	Subtotal Routine		298,649	273,990	273,778	114,421		41,098	41,067	17,163	232,891	232,711	97,257	-	-	-
8	Non-Routine															
9	Removal - Monroe Steam Plant	Annual	15,921	19,137	16,871	-	100%	19,137	16,871	-	-	-	-	-	-	-
10	Removal - Other Steam Plant	Annual	48,861	92,476	61,849	16,407	100%	92,476	61,849	16,407	-	-	-	-	-	-
11	Environmental & Other - Monroe	Annual	24,841	32,666	28,294	(4,261)	0%	-	-	-	32,666	28,294	(4,261)	-	-	-
12	Environmental & Other - Other Steam	Annual	14,434	11,690	44,987	41,758	0%	-	-	-	11,690	44,987	41,758	-	-	-
13	Subtotal Steam Production		104,057	155,969	152,002	53,904		111,614	78,720	16,407	44,356	73,281	37,497	-	-	-
14	Ludington	Annual	9,979	1,508	-	-	0%	-	-	-	1,508	-	-	-	-	-
15	Blue Water Energy Center (CCGT)	Annual	11,777	(4,512)	6,000	-	0%	-	-	-	(4,512)	6,000	-	-	-	-
16	BWEC Transmission Upgrades	Apr-22	5,506	(4,819)	-	-	0%	-	-	-	(4,819)	-	-	-	-	-
17	Blackstart Project 10570 & 20255	May-24	20,743	10,390	2,243	-	0%	-	-	-	-	33,376	-	10,390	(31,133)	-
18	Blackstart Project 17611	Nov-24	53	2,013	6,089	-	0%	-	-	-	-	8,155	-	2,013	(2,065)	-
19	Blackstart Project 18320	Mar-24	1,063	4,000	445	-	0%	-	-	-	-	5,508	-	4,000	(5,063)	-
20	Slocum Battery Pilot	Nov-24	7,562	10,111	26,832	129	0%	-	-	-	-	44,505	129	10,111	(17,673)	-
21	Trenton Channel Energy Center BESS	Mar-26	0	5,253	120,700	291,900	0%	-	-	-	-	-	-	5,253	120,700	291,900
22	Northeast 11-1 Decommissioning	Dec-25	-	294	312	-	100%	294	312	-	-	-	-	-	-	-
23	Subtotal Non-Routine		160,740	180,208	314,623	345,933		111,907	79,032	16,407	36,533	170,825	37,626	31,768	64,766	291,900
24	Total Capital Projects		459,389	454,198	588,401	460,353		153,006	120,098	33,570	269,424	403,537	134,884	31,768	64,766	291,900

Case No.: U-21534
Exhibit: A-12
Schedule: B5.1.1
Witness: M. E. Guillaumin
Page: 1 of 8

Commission-requested Monroe Power Plant FGD Asset Preservation Report



March 2024

INTRODUCTION

The Company installed flue-gas desulfurization (FGD) systems at Monroe Power Plant on all four units between 2009 and 2014. The Monroe FGD systems spray limestone slurry into exhaust flue gases to remove approximately 98% of sulfur dioxide (SO₂) emissions. The FGD systems include series of slurry tanks, pumps, and piping that are utilized to maintain high SO₂ emission removal efficiency while treating and disposing wastewater and gypsum created in the process.

The installation of the Monroe FGD systems was the first of its kind for the Company. No other power plant in the fleet operated a similar system for emissions compliance. Accordingly, the Company relied upon industry peer groups, the original equipment manufacturer (OEM), and OEM user groups to acquire knowledge and aide in the design, construction, and operation of the new FGD systems. Nevertheless, after years of operation, the FGD systems experienced several events that identified improvements were required for the Monroe units to be capable of returning to service in a timely manner following an extended unplanned loss of power to the FGDs. In 2019, the Company studied the design requirements needed to safely shutdown FGD operations and prevent the limestone slurries in the FGD tanks, pumps, and piping from solidifying and freezing when an unplanned power loss occurs. Preventing the slurries from solidifying and/or freezing is critical to recovering from a site blackout condition because once the slurries harden, it can take weeks to clear the tanks, pumps, and piping of solidified material at an extensive recovery cost. Until this solidified material is completely removed, the FGD system cannot be return to-service. Fully operational FGD systems are required for the power plant units to operate and generate power. Following the study, the Company determined the installation of four small, 1.5 MW diesel generators would provide sufficient back-up power to support emergency shutdown of FGD operations if the FGDs were to lose power. The backup generators were procured in 2021 and installed in 2023 at an average project cost of \$2.5 million per unit.

The purpose of this report is to supply the information requested in the Case No. U-21297 Final Order dated December 1, 2023, related to the Monroe FGD Asset Preservation (aka FGD Backup Generator) projects. Namely, this report demonstrates

the Company could not have avoided or minimized project costs if the back-up generators were installed with the initial FGD system. Additionally, this report explains the potential damages and delays associated with not having a backup power source to the FGDs and describes the future potential uses for the back-up generators after Monroe Power Plant units retire.

INSTALLING BACK-UP GENERATORS 15 YEARS AGO DURING INITIAL FGD CONSTRUCTION WOULD HAVE HAD SIMILAR COSTS TO INSTALLING THE BACK-UP GENERATORS AT THE PRESENT TIME

Overall, the design, equipment procured, and installation (and hence costs) would have been similar, whether the FGD back-up generators were installed 15 years ago during initial FGD construction or at the present time. Below details the factors that remain consistent between the projects being completed now or in the past.

- *Equipment Selection* - The Company would have chosen diesel generators as the back-up power system to the Monroe FGDs, whether the equipment was selected 15 years ago or in the present. Diesel generators provide the 24x7 dispatchability required to keep the FGDs' critical systems operational during a loss of power. Additionally, other fuel sources, such as natural gas, are not available on the Monroe Power Plant site at the volumes required to meet emergency generator fuel demands. Temporary rental systems, although considered as an alternative, were deemed to not be a viable alternative since the loss of power creates an immediate power need that cannot wait for hours or days until portable emergency generators can be sourced, transported, and connected to the four FGD sites. To expedite temporary power availability, the Company would need to provide dedicated siting that includes spill containment, switch gear, and other electrical connections to support the rental systems. Similarly, specific rental equipment would need to be dedicated to Monroe Power Plant use or there would not be an assurance of availability.

- *Technology* - Diesel engine technology has not materially changed for decades. Both now and in the past, diesel engines have been offered in standard sizes, such as 1.5 MW and 3.0 MW units.
- *Electrical Requirements* - The electrical configuration and back-up power requirements to operate the FGD systems have remained consistent since the FGDs were originally installed.
- *Physical Installation Location* - The siting of the generators would also have been the same, whether the installation occurred 15 years ago or in the present. The generators are located in a central location between all four units to minimize fuel piping required and allow for the reuse of existing FGD electrical conduit to make electrical tie-ins.

THE ABSENCE OF MONROE FGD BACK-UP POWER HAS THE POTENTIAL TO KEEP THE POWER PLANT IN OUTAGE FOR WEEKS AND REQUIRE EXTENSIVE RECOVERY COSTS

Monroe FGD systems handle vast quantities of water-based limestone slurry mixtures for removal of SO₂ from flue gases. The FGD systems are vulnerable to slurry settling and solidifying like concrete when agitators and pumps lose power. Additionally, the slurries will freeze if circulation is lost during cold weather. Once the slurry solidifies or freezes, a lengthy and expensive cleanup process is required to restore equipment to an operational state.

The Monroe FGD systems are comprised of many large vessels that handle slurry.

- Absorber tanks (4) are 61 feet in diameter and operate at an average level of 27 feet (or approximately 590,000 gallons of material per tank)
- Reagent feed tanks (3) are 36 feet in diameter and operate at a level of 30 feet (or approximately 230,000 gallons of material per tank)

- Filter feed tanks (2) are 34 feet in diameter and commonly contain 18 feet of slurry (or approximately 120,000 gallons of material per tank)
- Reclaim tanks (2) are 28 feet in diameter and operate a level of 15 feet (or approximately 70,000 gallons of material per tank)
- Chloride purge tanks (2) are 28 feet in diameter and operate at a level of 12 feet (or approximately 50,000 gallons of material per tank)

Removing solidified slurry mixtures from these tanks is no small feat. The tanks are accessible through small manholes as shown in Figure 1 below. Figure 1 shows one of the filter feed tank manhole doors removed following the failure of an agitator gearbox which resulted in the slurry to stop mixing. Following this failure, all of the gypsum solids in the slurry settled to the bottom of the tank and solidified in a concrete-like manner while all of the water from the slurry settled above the solidified gypsum. The solidified gypsum that was encountered was well above the level of the mandoor shown in Figure 1.

Figure 1 – Filter Feed Tank Manhole Access Door with severe pluggage



Solidified slurry is cleared from the tanks utilizing high pressure water and vacuuming. A tank can require beyond a week of labor to remove solidified slurry, and this does not

include removing pluggage and correcting damage to pumps, nozzles, bleed pumps, and associated piping. In the event the FGD system has no power, the large amounts of slurry removed would need to be trucked offsite where it would be treated and properly disposed of. Figure 2 below shows an example of the solidified slurry in the filter feed tank that was previously described in Figure 1. The solidified slurry in Figure 2 demonstrates the solidified gypsum after more than four shifts of high-pressure cleaning and vacuuming to get the solidified gypsum level down below the mandoor elevation.

Figure 2 – Solidified Slurry in the Filter Feed Tank following over four shifts of High-Pressure Cleaning and Vacuuming



In the end, if all four Monroe units were to experience a loss of power (blackout), it would require weeks of unit outage time and tens of millions of dollars of labor and specialty contractors and equipment to restore the FGD systems to an operational state.

**THE BACK-UP GENERATORS HAVE FUTURE USES BEYOND THE LIFE OF MONROE
POWER PLANT**

After Monroe Units 3 and 4 retire in 2028 and Monroe Units 1 and 2 retire in 2032, the FGD back-up generators can still serve purposes in the Company's fleet. The generators purchased are modular in nature and can be repurposed to serve several likely needs:

- *Blackstart Starting Engine* – Recovery from a blackout conditions typically starts with smaller generating unit(s) supplying enough auxiliary power to bring online larger generating units that can restore power to neighborhoods and bring online large power plants. The FGD back-up generators are of a suitable size and design to support restoring power to the grid.
- *Distribution System Power* – Distribution Operations utilizes generators of these size to temporarily restore local power to neighborhoods during power interruptions caused by storms and equipment failures. Generators are also utilized to temporarily provide power to neighborhoods as substation equipment is removed from service for upgrades.
- *Power Plant Equipment Back-up Power* – Loss of a transformer or electrical feed to major plant equipment can force a power plant offline. Back-up generators provide the redundancy needed to keep critical plant equipment operating.

THE MONROE FGD ASSET PRESERVATION PROJECTS ARE REASONABLE AND PRUDENT

The Commission requested this report to establish that the investments that the Company “seeks to recover could not have been avoided or minimized with reasonable and prudent design and initial installation of the FGD system, and if additional costs resulted from design failure.”¹ In addressing the Commission request, the Company has established that installing the back-up generators 15 years ago during initial FGD construction would have had similar costs to installing the back-up generators at the present time. Additionally, by actively taking part in industry peer groups and OEM user groups, the Company was prudent in ensuring that the initial design and installation of the FGD systems at Monroe Power Plant was in accordance with industry practice and did not experience any failure in design. The Company has gone a step further by demonstrating that an unplanned loss of power (blackout) while Monroe Power Plant units are in operation would result in an extensive recovery costs and prolonged, multi-week unit outages to clear solidified slurry that could not be properly evacuated if power were lost. Finally, the Company described the additional future uses of the generators post-Monroe retirement. All of these factors lead to the conclusion that installing FGD back-up generators at Monroe Power Plant was a reasonable and prudent investment.

¹ Case No. U-21297 December 1, 2023 Commission Order, p. 20.

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Midwest Energy Resources Company (MERC) & Fuel Supply
(\$000)

Case No.: U-21534
Exhibit No.: A-12
Schedule: B5.2
Witness: D. C. Milo
Page: 1 of 1

		(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures					
Line No.	Description	Historical	Projected Bridge Period			Projected Test Year	
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024 <i>col. (c)+(d)</i>	12 mos. ending 12/31/2025	
1	<u>MERC:</u>						
2	Conveyor Belting	563	112	-	112	-	
3	D11 Caterpillar Dozer	295	-	-	-	-	
4	85' Man Lift	153	-	-	-	-	
5	Large Mobile - Major Components (Engine, Transmission, etc.)	-	254	106	360	54	
6	Terminal Roadways & Railroad Tracks	-	117	-	117	-	
7	750KVA & 1500KVA Transformers	-	165	-	165	-	
8	Other Capital Spend <\$100K	213	278	184	462	100	
9	Total MERC	1,224	926	290	1,216	154	
10	<u>Fuel Supply:</u>						
11	Railcar truck/ draft system rebuilds	1,000	700	1,000	1,700	1,000	
12	Total Fuel Supply	1,000	700	1,000	1,700	1,000	
13	Total MERC and Fuel Supply	2,224	1,626	1,290	2,916	1,154	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant & Nuclear Fuel
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.3
Witness: J. C. Davis
Page: 1 of 6

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
Line No.	Description	Historical	Projected Bridge Period		Projected Test Year	
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024 <i>col. (c)+(d)</i>	12 mos. ending 12/31/2025
1	Nuclear Production Plant					
2	Routine and Small Projects 1/	81,269	66,265	68,892	135,157	42,450
3	Non-Routine and Large Projects 2/	<u>173,244</u>	<u>90,430</u>	<u>113,872</u>	<u>204,303</u>	<u>38,420</u>
4	Total Projects	<u>254,513</u>	<u>156,695</u>	<u>182,765</u>	<u>339,460</u>	<u>80,870</u>
5	Nuclear Fuel					
6	Uranium	-	48,048	-	48,048	61,379
7	Conversion	-	-	-	-	-
8	Enrichment	-	32,989	-	32,989	38,219
9	Fabrication	<u>3,246</u>	<u>28,970</u>	<u>2,000</u>	<u>30,970</u>	<u>35,478</u>
10	Total Nuclear Fuel	<u>3,246</u>	<u>110,008</u>	<u>2,000</u>	<u>112,008</u>	<u>135,077</u>
11	Total Capital Expenditures	<u>257,759</u>	<u>266,703</u>	<u>184,765</u>	<u>451,468</u>	<u>215,947</u>

1/ See Exhibit A-12, Schedule B5.3, Pages 2 and 3

2/ See Exhibit A-12, Schedule B5.3, Page 4

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant
Routine and Small Projects
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.3
Witness: J. C. Davis
Page: 2 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Capital Expenditures							
Line No.	Project Name	Historical	Projected Bridge Period		Projected Test Year		In Service Year
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
					col. (c)+(d)		
1	Routine and Small Projects						
2	Undervessel replacements	8,011	220	6,415	6,635	-	Annual
3	Visual Annunciator System (VAS) replacement	7,570	25	-	25	-	Annual
4	Security system computer	7,080	17,610	9,197	26,807	-	Annual
5	Plant radio system	4,176	6,050	1,498	7,548	-	Annual
6	Residual heat removal service water outlet valve (F068A/B) replacement	3,817	910	3,900	4,810	-	Annual
7	Environmentally Qualified (EQ) seal replacements	3,758	6	-	6	-	Annual
8	Safety relief valves (SRVs)	3,148	2,560	2,264	4,824	759	Annual
9	Snubbers	3,002	290	1,401	1,691	32	Annual
10	Low Pressure Turbine (LPT) expansion joints	2,423	-	-	-	-	Annual
11	Unitized actuators (UAs) replacement	2,389	740	4,660	5,400	230	Annual
12	Residual Heat Removal (RHR) motors replacement	2,374	3,620	2,744	6,364	949	Annual
13	High pressure stop and control valves (HPSV/HPCV) replacement	2,274	-	4,141	4,141	-	Annual
14	Reactor recirculation system (RRS) replacements	2,198	(206)	-	(206)	-	Annual
15	Main Steam Isolation Valves (MSIV) replacement	2,141	230	906	1,136	-	Annual
16	Low pressure stop and intercept valves (LPSV/LPIV) replacements	2,083	-	4,416	4,416	-	Annual
17	Valve replacements	2,066	1,020	1,220	2,240	-	Annual
18	Main steam bypass valve (MSBV) replacement	1,857	-	-	-	-	Annual
19	Core spray line vents	1,838	701	1,625	2,325	-	Annual
20	Diesel fire pump	1,720	167	-	167	-	Annual
21	Emergency equipment service water (EESW) pump	1,669	-	-	-	-	Annual
22	Motor operated valves (MOV)	1,619	-	-	-	-	Annual
23	Reactor Protection System (RPS) motor-generator (MG) set replacements	1,596	650	-	650	176	Annual
24	Emergency Diesel Generator (EDG) cylinder liner replacements	1,475	-	-	-	-	Annual
25	Flow accelerated corrosion (FAC) program piping insulation	1,229	80	758	838	-	Annual
26	Owner Controlled Area (OCA) security access control system	1,158	(609)	-	(609)	-	Annual
27	Residual heat removal service water (RHRSW) pump	974	-	-	-	-	Annual
28	Control rod drive mechanism (CRDM) replacement	916	4,550	603	5,153	4,867	Annual
29	Moisture separator reheater relief valve (MSRRV)	819	-	-	-	-	Annual

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant
Routine and Small Projects
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.3
Witness: J. C. Davis
Page: 3 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Capital Expenditures							
Line No.	Project Name	Historical	Projected Bridge Period			Projected Test Year	
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
					col. (c)+(d)		
30	General plant tools	688	3,800	2,504	6,304	3,375	Annual
31	Heater Drains Pump (HDP) replacement	593	13	-	13	-	Annual
32	Condensate pump	426	620	1,069	1,689	189	Annual
33	Residual Heat Removal (RHR) HVAC hydramotors	328	600	86	686	45	Annual
34	Breaker replacement	308	90	269	359	265	Annual
35	Plant wireless	297	1,840	5,871	7,711	-	Annual
36	Condensate filter demineralizer (CFD) septas	233	230	363	593	345	Annual
37	Refuel bridge mast	205	-	-	-	-	Annual
38	Refuel Floor monorail replacement	205	600	370	970	-	Annual
39	Switchyard footer replacement	194	237	132	369	-	Annual
40	Unitized Actuator shop	182	1,360	101	1,461	-	Annual
41	Hot machine shop	178	3,120	267	3,387	-	Annual
42	Contractor time & work tracking system	158	24	-	24	-	Annual
43	Piping replacements	106	3,860	752	4,612	-	Annual
44	Security defensive strategy simulator	106	-	-	-	-	Annual
45	Control rod blade (CRB) replacements	78	1,031	49	1,080	887	Annual
46	Pump and motor replacements	34	318	-	318	-	Annual
47	Reverse osmosis system replacement	21	-	-	-	2,597	Annual
48	Independent Spent Fuel Storage Installation (ISFSI) casks	2	47	689	736	282	Annual
49	Integrated Plant Computer System (IPCS) replacement	(10)	-	-	-	-	Annual
50	Paperless recorders replacement	(10)	-	131	131	124	Annual
51	Roof replacements	-	3,320	-	3,320	-	Annual
52	Neutron Monitoring System replacements	-	2,170	2,683	4,853	-	Annual
53	SCRAM discharge header	-	610	1,379	1,989	-	Annual
54	Temporary power modifications	-	450	1,945	2,395	-	Annual
55	Balance of plant (BOP) battery replacement	-	190	1,228	1,418	-	Annual
56	Reactor feed pump turbine (RFPT) rotor	-	-	1,721	1,721	-	Annual
57	Hydrogen seal replacement	-	-	1,181	1,181	-	Annual
58	Heater Feed Pump (HFP) replacement	-	-	340	340	-	Annual
59	Natural draft cooling towers	-	(775)	-	(775)	9,515	Annual
60	Document management system enhancements	-	-	-	-	9,992	Annual
61	Remote monitoring	-	-	-	-	4,473	Annual
62	Electronic work package system	-	-	-	-	2,584	Annual
63	GSW Pump House Critical Digital Asset (CDA)	-	-	-	-	745	Annual
64	Balance of Projects (<\$500K)	1,568	3,897	14	3,911	16	Annual
65	Total Routine and Small Projects	81,269	66,265	68,892	135,157	42,450	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Nuclear Production Plant
Non-Routine and Large Projects
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.3
Witness: J. C. Davis
Page: 4 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period			Projected Test Year	
		12 mos. ended	12 mos. ending	12 mos. ending	24 mos. ending	12 mos. ending	In Service
	Project Name	12/31/2022	12/31/2023	12/31/2024	12/31/2024	12/31/2025	Year
				col. (c)+(d)			
1	Non-Routine and Large Projects						
2	Main Unit Generator replacement	47,087	33,880	54,025	87,905	14,292	2026
3	Torus Vent Header	34,135	-	-	-	-	Annual
4	Underground safety-related service water piping	23,287	10,310	32,543	42,853	-	2024
5	Main Unit Generator rotor replacement	15,948	-	-	-	-	Annual
6	Generator excitation automatic voltage regulator (AVR)	11,028	14	-	14	-	Annual
7	Transformer #65 and #69 replacements	10,439	115	-	115	-	Annual
8	License renewal implementation (LRI)	5,755	7,750	7,554	15,304	729	2025
9	Circulating Water (CW) Discharge Pipe	5,251	-	-	-	734	Annual
10	Feed water heaters replacements	4,873	7,050	4,014	11,064	4,730	2026
11	Drywell Coolers #12 and #13	3,451	8	-	8	-	Annual
12	Boraflex fuel storage racks	3,397	2,920	1,126	4,046	-	2024
13	Radiation monitors	2,701	4,740	8,439	13,179	2,611	2024
14	Reactor Building Freight Elevator	1,900	2	-	2	-	Annual
15	Transformer replacements	1,625	312	-	312	-	Annual
16	Drywell Cooler #8	1,501	36	-	36	626	2026
17	Fire header restoration	840	4,010	-	4,010	-	Annual
18	Drywell Coolers #10 and #14	33	-	-	-	-	Annual
19	Off-gas chiller replacement	15	-	-	-	-	Annual
20	General Service Water (GSW) intake groin replacement	(18)	17,951	-	17,951	-	2024
21	Turbine Building moisture barrier	-	1,060	-	1,060	-	2024
22	Digital control modifications	-	270	-	270	-	Annual
23	Drywell moisture barrier replacement	-	-	2,766	2,766	-	2024
24	Fire detection system replacement	-	-	2,317	2,317	1,252	2024
25	Interruptable Air Supply (IAS) dryer replacements	-	-	825	825	-	Annual
26	Reactor recirculation motor-generator (RRMG) replacements	-	-	-	-	6,226	2026
27	Turbine controls replacements	-	-	263	263	762	Annual
28	Sanitary system replacement	-	-	-	-	6,457	Annual
29	Emergency Diesel Generator Service Water (EDGSW) piping	(4)	-	-	-	-	Annual
30	Other Capital Spend <\$100K	-	-	-	-	-	Annual
31	Total Non-Routine and Large Projects	173,244	90,430	113,872	204,303	38,420	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Nuclear Production Plant
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.3
Witness: J. C. Davis
Page: 5 of 6

(a)		(b)	(c)
Line No.	Description	Adjusted Historical 12 mos. ended 12/31/2022	Projected 12 mos. ending 12/31/2025
1	Nuclear Production Plant - Routine Expenditures AFUDC 1/	1,144	-
	<u>Nuclear Production Plant - Project Specific AFUDC</u>		-
2	Main Unit Generator replacement	5,462	10,643
3	Boraflex fuel storage racks	789	-
4	Underground safety-related service water piping	714	-
5	License renewal implementation (LRI)	703	121
6	Feed water heaters replacements	466	1,353
7	Transformer #65 and #69 replacements	322	-
8	Main Unit Generator rotor replacement	250	-
9	Torus Vent Header	221	-
10	Generator excitation automatic voltage regulator (AVR)	202	-
11	Drywell Cooler #8	135	185
12	Reactor Building Freight Elevator	116	-
13	Fire header restoration	88	-
14	Transformer Replacements	72	-
15	Circulating Water (CW) Discharge Pipe	45	-
16	Drywell Coolers #12 and #13	31	-
17	Radiation monitors	23	297
18	Off-gas chiller replacement	13	-
19	General Service Water (GSW) intake groin replacement	(18)	-
20	Reactor recirculation motor-generator (RRMG) replacements		211
21	Turbine controls replacements		-
22	Feedwater Heater controls replacements		18
23	Reactor feedpump turbine (RFPT) controls replacements		-
24	Reactor recirculation system (RRS) controls replacements		-
25	Motor Control Center Replacements		67
26	Sanitary system replacement		162
27	Interruptable Air Supply (IAS) dryer replacements		-
28	Fire detection system replacement		61
29	Drywell moisture barrier replacement		-
30	Turbine Building moisture barrier		-
31	Other Capital Spend <\$100K	-	-
32	Subtotal Project Specific	9,636	13,118
33	Total AFUDC - Nuclear Production Plant 2/	10,780	13,118

1/ AFUDC estimates for routine are developed at a high level based on historical trend

2/ The projected AFUDC amounts are based on the authorized U-21297 of 5.561%

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Nuclear Production Plant
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.3
Witness: J. C. Davis
Page: 6 of 6

Line No.	(a) Description	(b) In-Service Assumption	(c) 12 mos. ended 12/31/2022	(d) 12 mos. ending 12/31/2023	(e) 12 mos. ending 12/31/2024	(f) 12 mos. ending 12/31/2025	(g) Est. % Removal	(h) 12 mos. ending 12/31/2023	(i) 12 mos. ending 12/31/2024	(j) 12 mos. ending 12/31/2025	(k) 12 mos. ending 12/31/2023	(l) 12 mos. ending 12/31/2024	(m) 12 mos. ending 12/31/2025	(n) 12 mos. ending 12/31/2023	(o) 12 mos. ending 12/31/2024	(p) 12 mos. ending 12/31/2025
			Capital Expenditures (including Removal Costs)					Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
								col (d)x(g)	col (e)x(g)	col (f)x(g)				col (d)-(h)-(k)	col (e)-(i)-(l)	col (f)-(j)-(m)
1	Routine Projects	Annual	81,269	66,265	68,892	42,450	15%	9,940	10,334	6,368	56,325	58,559	36,083	-	-	-
2	Non-Routine Projects:															
3	Main Unit Generator replacement	May-26	47,087	33,880	54,025	14,292	15%	5,082	8,104	2,144	-	-	-	28,798	45,921	12,148
4	Torus Vent Header	Annual	34,135	-	-	-	15%	-	-	-	-	-	-	-	-	-
5	Underground safety-related service water	Jun-24	23,287	10,310	32,543	-	15%	1,547	4,881	-	-	56,219	-	8,764	(28,557)	-
6	Main Unit Generator rotor replacement	Annual	15,948	-	-	-	15%	-	-	-	-	-	-	-	-	-
7	Generator excitation automatic voltage reg	Annual	11,028	14	-	-	15%	2	-	-	12	-	-	-	-	-
8	Transformer #65 and #69 replacements	Annual	10,439	115	-	-	15%	17	-	-	98	-	-	-	-	-
9	Circulating Water (CW) Discharge Pipe	Annual	5,251	-	-	734	15%	-	-	110	-	-	624	-	-	-
10	Feed water heaters replacements	May-26	4,873	7,050	4,014	4,730	15%	1,058	602	710	-	-	-	5,993	3,412	4,021
11	Drywell Coolers #12 and #13	Annual	3,451	8	-	-	15%	1	-	-	7	-	-	-	-	-
12	Boraflex fuel storage racks	May-24	3,397	2,920	1,126	-	15%	438	169	-	-	6,327	-	2,482	(5,369)	-
13	Radiation monitors	Dec-24	2,701	4,740	8,439	2,611	15%	711	1,266	392	-	13,498	2,220	4,029	(6,325)	-
14	Reactor Building Freight Elevator	Annual	1,900	2	-	-	15%	0	-	-	2	-	-	-	-	-
15	Transformer replacements	Annual	1,625	312	-	-	15%	47	-	-	265	-	-	-	-	-
16	Drywell Cooler #8	May-26	1,501	36	-	626	15%	5	-	94	-	-	-	30	-	532
17	Fire header restoration	Annual	840	4,010	-	-	15%	601	-	-	3,408	-	-	-	-	-
18	Drywell Coolers #10 and #14	Annual	33	-	-	-	15%	-	-	-	-	-	-	-	-	-
19	Off-gas chiller replacement	Annual	15	-	-	-	15%	-	-	-	-	-	-	-	-	-
20	General Service Water (GSW) intake groi	Jan-24	(18)	17,951	-	-	15%	2,693	-	-	-	15,243	-	15,258	(15,243)	-
21	Turbine Building moisture barrier	Jan-24	-	1,060	-	-	15%	159	-	-	-	901	-	901	(901)	-
22	Drywell moisture barrier replacement	Jul-24	-	-	2,766	-	15%	-	415	-	-	2,351	-	-	-	-
23	Fire detection system replacement	Dec-24	-	-	2,317	1,252	15%	-	348	188	-	1,969	1,064	-	-	-
24	Interuptable Air Supply (IAS) dryer replace	Annual	-	-	825	-	15%	-	124	-	-	701	-	-	-	-
25	Reactor recirculation motor-generator (RF	May-26	-	-	-	6,226	15%	-	-	934	-	-	-	-	-	5,292
26	Digital control modifications	Annual	-	270	-	-	15%	41	-	-	230	-	-	-	-	-
27	Turbine controls replacements	Annual	-	-	263	762	15%	-	39	114	-	223	648	-	-	-
28	Sanitary system replacement	Annual	-	-	-	6,457	15%	-	-	969	-	-	5,488	-	-	-
29	Emergency Diesel Generator Service Wa	Annual	(4)	-	-	-	15%	-	-	-	-	-	-	-	-	-
30	Other Capital Spend <\$100K	Annual	-	-	-	-	15%	-	-	-	-	-	-	-	-	-
31	Sub-total Non-Routine Projects		<u>167,489</u>	<u>82,680</u>	<u>106,318</u>	<u>37,690</u>		<u>12,402</u>	<u>15,948</u>	<u>5,654</u>	<u>4,023</u>	<u>97,433</u>	<u>10,044</u>	<u>66,255</u>	<u>(7,063)</u>	<u>21,993</u>
32	Total Nuclear Projects		248,758	148,945	175,211	80,141		22,342	26,282	12,021	60,348	155,992	46,127	66,255	(7,063)	21,993
33	Fermi 2 License Renewal	1/ Apr-25	<u>5,755</u>	<u>7,750</u>	<u>7,554</u>	<u>729</u>		-	-	-	-	-	-	-	-	-
34	Total Nuclear Expenditures		254,513	156,695	182,765	80,870		22,342	26,282	12,021	60,348	155,992	46,127	66,255	(7,063)	21,993

1/ License Renewal is recorded to Plant Held for Future Use

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
M. Elliott Andahazy 3/
S. S. Deol 4/
S. M. Hartwick 5/
R. C. Steudle 6/
Page: 1 of 26

Line No.	(a) Description		(b) (c) (d) (e) (f) Capital Expenditures				
			Historical	Projected Bridge Period			Projected Test Year
			12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025
1	Base Capital Programs						
2	Emergent Replacements						
3	Storm	1/	181,326	281,848	244,066	525,914	251,144
4	Non - Storm	1/	263,014	207,192	220,275	427,467	226,663
5	Substation Reactive	1/	40,382	42,217	49,057	91,274	50,480
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	(20,820)	(20,820)	(21,436)
7	Subtotal Emergent Replacements		484,722	531,257	492,578	1,023,836	506,851
8	Customer Connections, Relocations & Other						
9	Connections and New Load	2/	214,093	216,938	206,069	423,006	218,608
10	Relocations	2/	22,776	45,774	52,202	97,977	35,991
11	Electric System Equipment	2/	30,180	33,655	33,300	66,955	34,266
12	NRUC and Improvement Blankets	2/	32,851	19,531	29,611	49,142	30,470
13	General Plant, Tools & Equipment and Miscellaneous	2/	8,103	5,886	9,144	15,031	9,410
14	Public Lighting Department Project	2/	13,440	1,920	-	1,920	-
15	Subtotal Customer Connections, Relocations & Other		321,443	323,703	330,327	654,031	328,745
16	Customer Advances for Construction	2/	(24,969)	(22,786)	(27,111)	(49,897)	(27,897)
17	Total Base Capital Programs		781,196	832,175	795,794	1,627,970	807,699
18	Strategic Capital Programs						
19	Infrastructure Resilience and Hardening	3/	418,440	376,177	295,363	671,539	364,706
20	Infrastructure Redesign and Modernization	4/	173,059	259,244	291,496	550,740	227,003
21	Technology and Automation	5/ 6/	123,441	165,605	121,919	287,524	235,571
22	Subtotal Strategic Capital Programs		714,939	801,026	708,777	1,509,803	827,280
23	Total Capital		1,496,136	1,633,201	1,504,572	3,137,772	1,634,979
24	Regulatory Asset						
25	Advanced Distribution Management System (ADMS)	7/	4,679	3,594	-	3,594	-

1/ Exhibit A-12, Schedule B5.4 - page 3

2/ Exhibit A-12, Schedule B5.4 - pages 4-9, lines 30, 50, 63, 77, 87, 88 & 90

3/ Exhibit A-12, Schedule B5.4 - page 13, line 37

4/ Exhibit A-12, Schedule B5.4 - page 16, line 111

5/ Exhibit A-12, Schedule B5.4 - page 19, line 55

6/ Tree Trim project sponsored by Company Witness R. Steudle

7/ Regulatory Asset treatment per Case No. U-20162

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
M. Elliott Andahazy 3/
S. S. Deol 4/
S. M. Hartwick 5/
R. C. Steudle 6/
Page: 2 of 26

Line No.	(a) Description		(b) Historical 12 mos. ended 12/31/2022	(c) Normalization Adjustment 8/	(d) Adjusted Historical Test Period sum (b) thru (c)	(e) 12 mos. ending 12/31/2023	(f) Projected Calendar Year		(g) 12 mos. ending 12/31/2025
							12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
1	Base Capital Programs								
2	Emergent Replacements								
3	Storm	1/	181,326	48,507	229,833	281,848	244,066	251,144	
4	Non - Storm	1/	263,014	(55,585)	207,429	207,192	220,275	226,663	
5	Substation Reactive	1/	40,382	5,814	46,196	42,217	49,057	50,480	
6	Emergent Replacement Reduction Based on Strategic Spend		-	-	-	-	(20,820)	(21,436)	
7	Subtotal Emergent Replacements		484,722	(1,263)	483,459	531,257	492,578	506,851	
8	Customer Connections, Relocations & Other								
9	Connections and New Load	2/	214,093			216,938	206,069	218,608	
10	Relocations	2/	22,776			45,774	52,202	35,991	
11	Electric System Equipment	2/	30,180			33,655	33,300	34,266	
12	NRUC and Improvement Blankets	2/	32,851			19,531	29,611	30,470	
13	General Plant, Tools & Equipment and Miscellaneous	2/	8,103			5,886	9,144	9,410	
14	Public Lighting Department Project	2/	13,440			1,920	-	-	
15	Subtotal Customer Connections, Relocations & Other		321,443			323,703	330,327	328,745	
16	Customer Advances for Construction	2/	(24,969)			(22,786)	(27,111)	(27,897)	
17	Total Base Capital Programs		781,196			832,175	795,794	807,699	
18	Strategic Capital Programs								
19	Infrastructure Resilience and Hardening	3/	418,440			376,177	295,363	364,706	
20	Infrastructure Redesign and Modernization	4/	173,059			259,244	291,496	227,003	
21	Technology and Automation	5/ 6/	123,441			165,605	121,919	235,571	
22	Subtotal Strategic Capital Programs		714,939			801,026	708,777	827,280	
23	Total Capital		1,496,136			1,633,201	1,504,572	1,634,979	
24	Regulatory Asset								
25	Advanced Distribution Management System (ADMS)	7/	4,679		4,679	3,594	-	-	

1/ Exhibit A-12, Schedule B5.4 - page 3

2/ Exhibit A-12, Schedule B5.4 - pages 4-9, lines 30, 50, 63, 77, 87, 88 & 90

3/ Exhibit A-12, Schedule B5.4 - page 13, line 37

4/ Exhibit A-12, Schedule B5.4 - page 16, line 111

5/ Exhibit A-12, Schedule B5.4 - page 19, line 55

6/ Tree Trim project sponsored by Company Witness R. Steudle

7/ Regulatory Asset treatment per Case No. U-20162

8/ Normalization Adjustment:

Emergent Replacements Exh. B5.4, p.3, Line 24, col. (j)

Amount
(1,263)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Emergent Replacements
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
Page: 3 of 26

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Description	Capital Expenditures						1/1/2025 - 12/31/2025 Test Year	1/1/2022 - 12/31/2022 Historical	Emergent Replacements Adjustment	In Service Year
		Historical 12 mos. ended 12/31/2018	Historical 12 mos. ended 12/31/2019	Historical 12 mos. ended 12/31/2020	Historical 12 mos. ended 12/31/2021	Historical 12 mos. ended 12/31/2022	Historical 5-year average				
							1/			(h) - (i)	
1	Base Capital Programs										
2	Emergent Replacements										
3	Storm	142,108	178,931	150,897	395,286	181,326	209,710				Annual
4	Inflation Adjustment	23,437	25,825	19,731	31,623	-	20,123				
5	Inflation Adjusted Historical Capital	165,545	204,756	170,628	426,909	181,326	229,833	229,833	181,326	48,507	
6	Inflation 1/1/23 -12/31/23 3.20%							7,355	5,802	1,552	
7	Inflation 1/1/24 -12/31/24 2.90%							6,878	5,427	1,452	
8	Inflation 1/1/25 -12/31/25 2.90%							7,078	5,584	1,494	
9	Projected Storm Replacements							251,144	198,139	53,005	
10	Non-Storm	159,555	163,112	155,324	209,236	263,014	190,048				Annual
11	Inflation Adjustment	26,315	23,542	20,310	16,739	-	17,381				
12	Inflation Adjusted Historical Capital	185,870	186,654	175,634	225,975	263,014	207,429	207,429	263,014	(55,585)	
13	Inflation 1/1/23 -12/31/23 3.20%							6,638	8,416	(1,779)	
14	Inflation 1/1/24 -12/31/24 2.90%							6,208	7,871	(1,664)	
15	Inflation 1/1/25 -12/31/25 2.90%							6,388	8,100	(1,712)	
16	Projected Non-Storm Replacements							226,663	287,402	(60,739)	
17	Substation Reactive	44,275	40,386	38,131	46,008	40,382	41,837				Annual
18	Inflation Adjustment	7,302	5,829	4,986	3,681	-	4,360				
19	Inflation Adjusted Historical Capital	51,577	46,215	43,118	49,689	40,382	46,196	46,196	40,382	5,814	
20	Inflation 1/1/23 -12/31/23 3.20%							1,478	1,292	186	
21	Inflation 1/1/24 -12/31/24 2.90%							1,383	1,209	174	
22	Inflation 1/1/25 -12/31/25 2.90%							1,423	1,244	179	
23	Projected Substation Reactive Replacements							50,480	44,126	6,353	
24	Total Emergent Replacements Normalization Adjustment (Line 5 + Line 12 + Line 19) Pre-inflation							483,459	484,722	(1,263)	2/
25	Inflation 1/1/23 -12/31/23 3.20%							15,471	15,511	(40)	
26	Inflation 1/1/24 -12/31/24 2.90%							14,469	14,507	(38)	
27	Inflation 1/1/25 -12/31/25 2.90%							14,889	14,927	(39)	
28	Total Projected Emergent Replacements Expense (Line 9 + Line 16 + Line 23)							528,287	529,667	(1,381)	
29	Test Year Emergent Replacement Reduction Based on Strategic Spend							(21,436)			3/
30	Total Projected Emergent Replacements Expense less Test Year Emergent Reduction based upon Strategic Spend							506,851			

1/ Five year average of actual expenditures adjusted for inflation is included in this request

2/ Historical normalization adjustment carried to Base Capital Programs - see Exhibit A-12, B5.4, page 2, line 7, col. (c)

3/ Test Year Emergent Replacement Reduction Based on Strategic Spend carried from Distribution Plant - See Exhibit A-12, B5.4, page 1, line 6, col. (f)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
P. Bennett 2/
Page: 4 of 26

		(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description						
		Historical 12 mos. ended 12/31/2020	Historical 12 mos. ended 12/31/2021	Historical 12 mos. ended 12/31/2022	Historical 3-year average		
1	Connections and New Load						
2	Small Load Growth Projects (Blanket)	18,053	21,661	18,236	19,317		
3	Inflation Adjustment	2,361	1,733	-	1,364		
4	Inflation Adjusted Historical Capital	20,413	23,394	18,236	20,681		
5	Projected Small Load Growth Projects (Blanket)						
5	Customer Connections	89,211	108,810	123,726	107,249		
6	Inflation Adjustment	11,665	8,705	-	6,790		
7	Inflation Adjusted Historical Capital	100,877	117,515	123,726	114,039		
8	Customer Connections CIAC	(14,756)	(15,524)	(17,654)	(15,978)		
9	Inflation Adjustment	(1,930)	(1,242)	-	(1,057)		
10	Inflation Adjusted Historical Capital	(16,686)	(16,766)	(17,654)	(17,036)		
11	Customer Connections (Net of CIAC)	74,455	93,286	106,072	91,271		
12	Inflation Adjustment	9,736	7,463	-	5,733		
13	Inflation Adjusted Historical Capital	84,191	100,749	106,072	97,004		
14	Projected Customer Connections						
15	Projected Customer Connections CIAC						
16	Projected Customer Connections (Net of CIAC)						
17	New Business Projects	29,957	54,361	72,131	52,150		
18	Inflation Adjustment	3,917	4,349	-	2,755		
19	Inflation Adjusted Historical Capital	33,874	58,710	72,131	54,905		
20	New Business Projects CIAC	(4,709)	(9,390)	(5,151)	(6,417)		
21	Inflation Adjustment	(616)	(751)	-	(456)		
22	Inflation Adjusted Historical Capital	(5,325)	(10,141)	(5,151)	(6,872)		
23	New Business Projects (Net of CIAC)	25,248	44,971	66,980	45,733		
24	Inflation Adjustment	3,301	3,598	-	2,300		
25	Inflation Adjusted Historical Capital	28,549	48,569	66,980	48,033		
26	Projected New Business Projects						
27	Projected New Business Projects CIAC						
28	Projected New Business Projects (net of CIAC)						
29	Incremental Infrastructure for EV						
30	Total Connections and New Load			214,093			
31	Total Connections and New Load CIAC			(22,805)			
32	Total Connections and New Load (Net of CIAC)			191,288			

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill
P. Bennett 2/
Page: 5 of 26

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Projected Calendar Year			Bridge Period	Test Year	
Line No.	Description	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	In Service Year
1	Connections and New Load						
2	Small Load Growth Projects (Blanket)						Annual
3	Inflation Adjustment						
4	Inflation Adjusted Historical Capital						
5	Projected Small Load Growth Projects (Blanket)	18,026	21,962	22,599	39,988	22,599	
5	Customer Connections						Annual
6	Inflation Adjustment						
7	Inflation Adjusted Historical Capital						
8	Customer Connections CIAC						
9	Inflation Adjustment						
10	Inflation Adjusted Historical Capital						
11	Customer Connections (Net of CIAC)						
12	Inflation Adjustment						
13	Inflation Adjusted Historical Capital						
14	Projected Customer Connections	123,306	121,101	124,613	244,407	124,613	
15	Projected Customer Connections CIAC	(16,782)	(18,091)	(18,615)	(34,873)	(18,615)	
16	Projected Customer Connections (Net of CIAC)	106,524	103,011	105,998	209,535	105,998	
17	New Business Projects						Annual
18	Inflation Adjustment						
19	Inflation Adjusted Historical Capital						
20	New Business Projects CIAC						
21	Inflation Adjustment						
22	Inflation Adjusted Historical Capital						
23	New Business Projects (Net of CIAC)						
24	Inflation Adjustment						
25	Inflation Adjusted Historical Capital						
26	Projected New Business Projects	75,606	58,305	59,996	133,911	59,996	
27	Projected New Business Projects CIAC	(5,847)	(7,298)	(7,510)	(13,145)	(7,510)	
28	Projected New Business Projects (net of CIAC)	69,759	51,007	52,486	120,766	52,486	
29	Incremental Infrastructure for EV	-	4,700	11,400	4,700	11,400	Annual
30	Total Connections and New Load	216,938	206,069	218,608	423,006	218,608	
31	Total Connections and New Load CIAC	(22,629)	(25,388)	(26,125)	(48,017)	(26,125)	
32	Total Connections and New Load (Net of CIAC)	194,309	180,680	192,484	374,989	192,484	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
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Witness: B. L. Hill
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description		Historical 12 mos. ended 12/31/2020	Historical 12 mos. ended 12/31/2021	Historical 12 mos. ended 12/31/2022	Historical 3-year average
33	Relocations					
34	Small Relocations Projects (Blanket)		14,943	7,018	8,439	10,133
35	Inflation Adjustment		1,954	561	-	838
36	Inflation Adjusted Historical Capital		16,897	7,579	8,439	10,972
34	Projected Small Relocation Projects (Blanket)					
35	Major Infrastructure Relocation Project					
36	Gordie Howe International Bridge				235	
37	I-375 Relocations				-	
38	Relocation Projects (excl. Major Infrastructure Projects)	1/	10,059	17,089	14,103	13,750
39	Inflation Adjustment		1,315	1,367	-	894
40	Inflation Adjusted Historical Capital		11,374	18,456	14,103	14,644
41	Relocation Projects CIAC		(1,930)	(483)	(2,163)	(1,525)
42	Inflation Adjustment		(252)	(39)	-	(97)
43	Inflation Adjusted Historical Capital		(2,182)	(521)	(2,163)	(1,622)
44	Relocation Projects (Net of CIAC)		8,129	16,606	11,939	12,225
45	Inflation Adjustment		1,063	1,328	-	797
46	Inflation Adjusted Historical Capital		9,192	17,934	11,939	13,022
47	Relocation Projects (excl. Major Infrastructure Projects)	3/				
48	Relocation Projects CIAC					
49	Subtotal Relocation Projects (Net of CIAC)					
50	Total Relocations				22,776	
51	Total Relocations CIAC				(2,163)	
52	Total Relocations (Net of CIAC)				20,613	
53	Electric System Equipment					
54	Distribution Transformers & Regulators	4/			9,027	
55	Major Equipment		21,435	13,594	5,552	13,527
56	Inflation Adjustment		2,803	1,088	-	1,297
57	Inflation Adjusted Historical Capital		24,238	14,682	5,552	14,824
58	Meters		16,891	13,800	15,601	15,431
59	Inflation Adjustment		2,209	1,104	-	1,104
60	Inflation Adjusted Historical Capital		19,100	14,905	15,601	16,535
61	Projected Major Equipment					
62	Projected Meters					
63	Total Electric System Equipment				30,180	

Michigan Public Service Commission
DTE Electric Company
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Projected Calendar Year			Bridge Period	Test Year	
Line No.	Description	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	In Service Year
33	Relocations						
34	Small Relocations Projects (Blanket)						Annual
35	Inflation Adjustment						
36	Inflation Adjusted Historical Capital						
34	Projected Small Relocation Projects (Blanket)	7,787	11,651	11,989	19,438	11,989	
35	Major Infrastructure Relocation Project						
36	Gordie Howe International Bridge	-	-	-	-	-	2022
37	I-375 Relocations	5,938	25,000	8,000	30,938	8,000	2025
38	Relocation Projects (excl. Major Infrastructure Projects)						Annual
39	Inflation Adjustment						
40	Inflation Adjusted Historical Capital						
41	Relocation Projects CIAC						
42	Inflation Adjustment						
43	Inflation Adjusted Historical Capital						
44	Relocation Projects (Net of CIAC)						
45	Inflation Adjustment						
46	Inflation Adjusted Historical Capital						
47	Relocation Projects (excl. Major Infrastructure Projects)	32,050	15,551	16,002	47,601	16,002	
48	Relocation Projects CIAC	(157)	(1,723)	(1,773)	(1,879)	(1,773)	
49	Subtotal Relocation Projects (Net of CIAC)	31,893	13,828	14,229	45,722	14,229	
50	Total Relocations	45,774	52,202	35,991	97,977	35,991	
51	Total Relocations CIAC	(157)	(1,723)	(1,773)	(1,879)	(1,773)	
52	Total Relocations (Net of CIAC)	45,618	50,480	34,219	96,097	34,219	
53	Electric System Equipment						
54	Distribution Transformers & Regulators	5,586	-	-	5,586	-	Annual
55	Major Equipment						Annual
56	Inflation Adjustment						
57	Inflation Adjusted Historical Capital						
58	Meters						Annual
59	Inflation Adjustment						
60	Inflation Adjusted Historical Capital						
61	Projected Major Equipment	12,748	15,742	16,198	28,489	16,198	
62	Projected Meters	15,321	17,559	18,068	32,880	18,068	
63	Total Electric System Equipment	33,655	33,300	34,266	66,955	34,266	

Michigan Public Service Commission
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description		Historical 12 mos. ended 12/31/2020	Historical 12 mos. ended 12/31/2021	Historical 12 mos. ended 12/31/2022	Historical 3-year average
64	NRUC and Improvement Blankets	5/				
65	System Improvements		12,117	9,715	22,289	14,707
66	Inflation Adjustment		1,584	777	-	787
67	Inflation Adjusted Historical Capital		13,702	10,493	22,289	15,495
68	Normal Retirement Unit Changeouts (NRUC)		7,398	5,702	4,981	6,027
69	Inflation Adjustment		967	456	-	475
70	Inflation Adjusted Historical Capital		8,366	6,158	4,981	6,501
71	Operational Technologies		5,401	5,535	5,581	5,506
72	Inflation Adjustment		706	443	-	383
73	Inflation Adjusted Historical Capital		6,108	5,978	5,581	5,889
74	Projected System Improvements					
75	Projected Normal Retirement Unit Changeouts (NRUC)					
76	Projected Operational Technologies					
77	Total NRUC and Improvement Blankets				32,851	
78	General Plant, Tools & Equipment and Miscellaneous					
79	Substation Physical Security		562	1,753	655	990
80	Inflation Adjustment		74	140	-	71
81	Inflation Adjusted Historical Capital		636	1,893	655	1,061
82	General Plant, Tools & Equipment and Miscellaneous		8,007	5,692	7,448	7,049
83	Inflation Adjustment		1,047	455	-	501
84	Inflation Adjusted Historical Capital		9,054	6,148	7,448	7,550
85	Projected Substation Physical Security					
86	Projected General Plant, Tools & Equipment and Miscellaneous					
87	Total General Plant, Tools & Equipment and Miscellaneous				8,103	
88	Public Lighting Department Project				13,440	
89	Total Customer Connections, Relocations & Other				321,443	
90	Total Cust Connections, Relocations & Other CIAC				(24,969)	
91	Total Cust Connections, Relocations & Other Net of CIAC				<u>296,474</u>	

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DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
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	(a)	(b)	(c)	(d)	#	(e)	(f)	(g)
Line No.	Description	Capital Expenditures				Bridge Period	Test Year	In Service Year
		Projected Calendar Year						
		12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025				
64	NRUC and Improvement Blankets							
65	System Improvements							Annual
66	Inflation Adjustment							
67	Inflation Adjusted Historical Capital							
68	Normal Retirement Unit Changeouts (NRUC)							Annual
69	Inflation Adjustment							
70	Inflation Adjusted Historical Capital							
71	Operational Technologies							Annual
72	Inflation Adjustment							
73	Inflation Adjusted Historical Capital							
74	Projected System Improvements	7,797	16,454	16,931		24,252	16,931	
75	Projected Normal Retirement Unit Changeouts (NRUC)	4,432	6,904	7,104		11,336	7,104	
76	Projected Operational Technologies	7,301	6,253	6,435		13,554	6,435	
77	Total NRUC and Improvement Blankets	19,531	29,611	30,470		49,142	30,470	
78	General Plant, Tools & Equipment and Miscellaneous							
79	Substation Physical Security							Annual
80	Inflation Adjustment							
81	Inflation Adjusted Historical Capital							
82	General Plant, Tools & Equipment and Miscellaneous							Annual
83	Inflation Adjustment							
84	Inflation Adjusted Historical Capital							
85	Projected Substation Physical Security	544	1,127	1,160		1,671	1,160	
86	Projected General Plant, Tools & Equipment and Miscellaneous	5,342	8,017	8,250		13,359	8,250	
87	Total General Plant, Tools & Equipment and Miscellaneous	5,886	9,144	9,410		15,031	9,410	
88	Public Lighting Department Project	1,920	-	-		1,920	-	2023
89	Total Customer Connections, Relocations & Other	323,703	330,327	328,745		654,031	328,745	
90	Total Cust Connections, Relocations & Other CIAC	(22,786)	(27,111)	(27,897)		(49,897)	(27,897)	
91	Total Cust Connections, Relocations & Other Net of CIAC	300,918	303,216	300,848		604,134	300,848	

1/ Exhibit A-12, Schedule B5.4 - page 11, line 84

2/ Incremental EV Chargers sponsored by Witness P. Bennett

3/ Exhibit A-12, Schedule B5.4 - page 12, line 30

4/ Distribution Transformers & Regulators will be charged to specific projects in 2024 and excluded from historical average

5/ Batteries and Chargers Replacement Program moved to Infrastructure Resilience and Hardening pillar as a standalone program and Animal Mitigation become part of the Frequent Outage Programs (CEMI) per Staff request in U-20836

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Prior Year's Projects
(\$000)

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(a)		(b)
Line No.	Description	Historical 12 mos. ended 12/31/2022
1	Prior Year's New Business Projects:	
2	Morton (MORTN) Sub - Overhead Circuits (Sheldon/Gilbert/Zac)	12,992
3	MOUNTAIN Skid-Mounted Sub	7,222
4	Nitro Sub - CKT 1 & 2 (south and north of Napier)	4,778
5	Saturn 3rd Transformer	3,715
6	Emerald Business Park (EBP)	3,513
7	New Class I for Verizon Wireless	3,285
8	CORKT Ford Circuits	2,907
9	Undesignated Capital	2,113
10	Globe Substation Engineering - DC8034	2,111
11	KERN Substation Upgrades	2,058
12	WSU Gateway Theatre Complex	1,944
13	GRAYL DC8517 Circuit Load Relief	1,938
14	Ferrous Processing -9100 John Kronk	1,772
15	Henry Ford Macomb Hospital New Class I Substation	1,663
16	Blakes Cider Mill - Armada DC8550	1,630
17	MSV MI LLC, 1721 W Pleasant St., River Rouge, MI	1,579
18	RotoZ Dairy MOS (Convert portion of SNOVR0301)	1,299
19	Port Hope Substation (Sub and OH work)	1,204
20	Padnos	1,165
21	SIGMA (Grayling) Substation OH UG Circuits	1,026
22	Wolverine Packing Facility	992
23	New AKRON Circuit (Wanxiang, Novi Sr Living)	974
24	Ford R&E: Explorer Sub	782
25	NINMI Circuit -MOS	773
26	PHENX DC 9821- Mid Michigan Materials	732
27	Morton Substation	701
28	770 S Adams MOS	641
29	Buhl Building - 535 Griswold Ave	598
30	Verizon- 21009 Lahser New Load MOS	590
31	420 S. Lafayette Relocation	510
32	Kings Point (Gratiot- Macomb) - Property	451
33	Sterling Group- Former JLA - Phase 1 of 3	447
34	Project Panda - 1200 W State Fair Ave, Detroit	434
35	602 E. Washington Overhead Removal	364
36	CATLI MOS 13 Switchgear (S. Glenwood, Pontiac)	299
37	MAS 12200 Oakland Park	263
38	AMAZON - 13751 Hamilton Ave, Highland Park	260
39	GM Pontiac - Tempest Substation Upgrades - Phase I	258
40	TAMRK New Circuit DC8258	223
41	New DC: Whittier Substation	212
42	HUDROE Development	195
43	Kings Point (Gratiot- Macomb) Area Plan - Substation	167
44	Nitro Sub - CKT 3 & 4 (5 mile, Napier & Riidge)	155
45	MOS Ashley Capitol POLRS & LIVON	150
46	Quaker Transformer Upgrade	115

Michigan Public Service Commission
DTE Electric Company
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(a)		(b)
Line No.	Description	Historical 12 mos. ended 12/31/2022
47	T-Mobile, new circuit OTTWA	98
48	Seaside substation modifications Corteva	84
49	OMEGA - BOYNE load transfer	77
50	Combine International (Lombard Subs)	76
51	Henry West Residential	69
52	Wayne Criminal Justice Center - CJC CUP	56
53	Nitro Substation	55
54	Airport Substation Expansion	54
55	SWANC Substation Expansion	43
56	Northland Apartments A and B	37
57	MOS Blanche Sims Elementary School	36
58	CORKT Substation Conduit	36
59	Port Hope Substation	33
60	ESOC Electric Service	28
61	TAMRK Future Circuit DC #9	24
62	120-kV feed to Great Lakes Water Authority (GLWA)	21
63	CODY 8939 New Residential Load	20
64	Ann Arbor Solar	20
65	Fairgrove Substation -Property	13
66	SIGMA (Grayling) DC 8587 GRAYL Circuit Split	11
67	Hood Substation - Village at Bloomfield	9
68	Airport Substation Expansion - Property	7
69	Ashley Capital Crossroads North	5
70	Reservice Children's Hospital of Michigan (CHOM) From MIDTN	4
71	Eastland Commerce Center MOS	4
72	GENL0072-01 Metamora Substation - Proper	4
73	Alamo Sub Expand - Brose	4
74	Terry Leright Service Planning Request	2
75	North Ashley Relocation	2
76	Book Tower 1265 Washington	2
77	Miscellaneous	1
78	FALCN/CYPRS New Class 'R' 120-13.2kV	1
79	New 6.6 MVAR Cap at Derby (Vassar Acquisitions LLC)	1
80	CATLI Substation Upgrade (CATLI, Gleenwod, Rubicon)	0
81	Valeo (CORTL)	0
82	1400 E 10 Mile Rd, Hazel Park - 10 MVA Sub Ashley (Eclipse)	0
83	American Axle PL9178	(4)
84	Total Prior Year's New Business Projects	72,131

Michigan Public Service Commission
DTE Electric Company
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Distribution Plant - Prior Year's Projects
(\$000)

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(a)

(b)

Line No.	Description	Historical 12 mos. ended 12/31/2022
1	<u>Prior Year's Relocation Projects:</u>	
2	Mound Road Relocation- Phase 2	3,460
3	Mound Road Relocation- Phase 1	2,417
4	New Boston Township Relocation	2,274
5	I-94 Cass Bridge Relocation (MDOT)	2,270
6	I-75 Conflict 511 (MDOT)	1,448
7	Allen Road Railroad Project	609
8	Trk 2107A-B Relocation	382
9	MH 2598 John Road Relo	357
10	Grand River I-94 Bridge Reconstruction (MDOT)	282
11	TRK 422, 459 Decommission - 428 Relocation, Lynch Subst	262
12	TRK 5906 Relocation Project	120
13	Chase Rd Relocation	100
14	Tie 1473 Reloc for ITC Tower Replacement	24
15	Ford Oakwood Blvd OH to UG Relocation	24
16	I-94 Conner crossing_UG	21
17	Mt. Elliot I-94 Bridge Relocation	21
18	Ecorse Southfield bridge UG Relo	15
19	RELO0075-01 I-94 Holcomb crossing UG	11
20	33 Eliot CCA Midtown Facility Relocation	9
21	Park Rd (SPRUC) Pole Relocation	3
22	Bates & Monroe Alley Relocation	3
23	Tie 810 relocation Palms and Gratiot	2
24	Maple Road Relocation	1
25	Relocate TRK1418	1
26	City of Dearborn/Ford Relocation	1
27	Consumers Energy Pipeline Relocation	0
28	Temple West Alley Reloc	(6)
29	Warren Rd Relocation	(7)
30	Total Prior Year's Relocation Projects	<u>14,103</u>

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Resilience and Hardening
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Capital Expenditures						
		Historical	Projected Calendar Year			Bridge Period	Test Year	
Line No.	Description	12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	In Service Year
1	<u>Infrastructure Resilience and Hardening</u>							
2	Mobile Fleet Program	15,234	2,804	5,000	1,500	7,804	1,500	Annual
3	Substation Risk: Drexel	1,898	640	-	-	640	-	2023
4	Substation Risk: Chestnut	64	989	2,725	7,881	3,715	7,881	2025
5	Substation Risk: Savage	577	11	-	-	11	-	2023
6	Substation Risk: Apache	4,653	8,492	3,810	-	12,302	-	2024
7	Substation Risk: Port Huron	184	3	-	-	3	-	2022
8	Substation Risk: Belleville Switchgear Decommission	1,234	1,313	-	-	1,313	-	2023
9	Substation Risk: McGraw	12,699	6,310	37,852	-	44,162	-	2024
10	Substation Risk: Voyager	201	2	-	-	2	-	2023
11	Substation Risk: Flood Defense Program	87	269	5,009	-	5,278	-	2024
12	4.8 kV Hardening	157,482	127,010	80,000	125,000	207,010	125,000	Annual
13	Pole and Pole Top Maintenance and Modernization (PTMM)	83,934	79,075	63,450	121,000	142,525	121,000	Annual
14	Cable Replacement Program	27,746	22,832	15,001	16,501	37,833	16,501	Annual
15	Frequent Outage Program (CEMI)	2/ 60,067	63,963	48,050	62,504	112,013	62,504	Annual
16	Breaker Replacement Program	14,415	13,161	-	-	13,161	-	Annual
17	Pontiac Vaults	1,263	657	-	-	657	-	2023
18	URD Replacement Program	7,043	12,417	-	-	12,417	-	Annual
19	URD Replacement Program: Detroit URD 1-1	1,154	285	-	-	285	-	2023
20	40 kV: Automatic Pole Top Switch	4,375	6,358	4,995	4,995	11,353	4,995	Annual
21	Disconnect and Switcher Replacement	4,182	15,457	4,900	4,900	20,357	4,900	Annual
22	Steel Pole Highway Crossings	1,880	1,734	5,000	5,000	6,734	5,000	Annual
23	Station Upgrade: Warren (Relay Replacement)	271	649	-	-	649	-	2022
24	Station Upgrade: Northeast (Relay Replacement)	13,279	3,652	-	-	3,652	-	2023
25	Batteries and Chargers Replacement Program	1/ 2,849	3,343	2,500	3,030	5,843	3,030	Annual
26	Substation Risk: Hood	-	249	6,918	978	7,167	978	2025
27	Substation Risk: UNVIL 301 B1 Conversion	-	112	-	-	112	-	2023
28	Portable Generators	3/ -		4,500	-	4,500	-	2024
29	Station Upgrade: Lincoln	-	-	-	330	-	330	2027
30	SCADA Pole Top Device Replacement	764	1,694	1,808	2,038	3,502	2,038	2035
31	Substation Regulator Replacement	685	1,337	816	822	2,153	822	2027
32	Station Upgrade: Navarre	-	-	330	5,300	330	5,300	2026
33	Station Upgrade: 120kV Relays Upgrade for ITC Projects	222	1,359	2,698	2,485	4,056	2,485	2035
34	Substation Risk: Savage Switchgear Replacement	-	-	-	100	-	100	2027
35	Substation Risk: Seville	-	-	-	243	-	243	2027
36	Substation Risk: Imlay	-	-	-	100	-	100	2030
37	Total Infrastructure Resilience and Hardening Projects and Programs	418,440	376,177	295,363	364,706	671,539	364,706	

1/ Batteries and Chargers Replacement Program moved to Infrastructure Resilience and Hardening pillar as a standalone program per Staff request in U-20836

2/ Animal Mitigation moved to the Frequent Outage Programs (CEMI) per Staff request in U-20836

3/ Portable Generators sponsored by Company Witness B. L. Hill

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

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(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Capital Expenditures						
Line No.	Description	Historical	Projected Calendar Year			Bridge Period	Test Year	In Service Year
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
1	Infrastructure Redesign and Modernization							
2	Ann Arbor System Improvements: State Substation	5,996	2,543	-	-	2,543	-	2023
3	Ann Arbor System Improvements: Apex (Blue) Substation	3,484	1,478	-	-	1,478	-	2023
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	787	334	3,000	9,230	3,334	9,230	2024
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	1,947	2,477	4,745	4,736	7,221	4,736	Annual
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	191	160	-	-	160	-	2022
7	Subtransmission Redesign & Rebuild: Trunk 7106	175	(90)	-	-	(90)	-	2022
8	Subtransmission Redesign & Rebuild: Trunk 2255	2,473	698	-	-	698	-	2023
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	1,174	207	-	-	207	-	2022
10	Subtransmission Redesign & Rebuild: Trunk 7333	1,300	168	-	-	168	-	2022
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	67	4,070	-	4,137	-	2024
12	Subtransmission Redesign & Rebuild: Boyne	14,072	8,309	3,026	-	11,336	-	2024
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1	8,226	1,448	-	-	1,448	-	2023
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3	3,262	13,753	2,259	-	16,013	-	2024
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4	2,808	-	-	-	-	-	2025
16	Subtransmission Redesign & Rebuild: Tie 1568	64	645	-	-	645	-	2023
17	Subtransmission Redesign & Rebuild: Trunk 4217	331	1,921	2,265	2,360	4,186	2,360	2025
18	Subtransmission Redesign & Rebuild: Trunk 3509	126	2,284	3,653	-	5,937	-	2024
19	Subtransmission Redesign & Rebuild: Trunk 4266	3						2025
20	Subtransmission Redesign & Rebuild: Praxair	-	-	565	2,000	565	2,000	2025
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	-	4	500	-	504	-	2024
22	Subtransmission Breaker Short Circuit Violations	1,645	2,864	50	-	2,914	-	2024
23	Subtransmission Redesign & Rebuild: Slocum	125	511	-	-	511	-	2023
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	2,670	2,717	260	-	2,977	-	2024
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-	-	-	-	2025
26	TCHPP Switchyard Upgrades	-	2,334	3,309	20	5,642	20	2025
27	Trunk and Tie Lines Hardening Program: Prior Year's	(2)	-	-	-	-	-	2022
28	CODI: Charlotte Network Upgrade	8,319	8,727	10,967	11,884	19,693	11,884	2025
29	CODI: Targeted Network Secondary Cable Replacement	1,987	4,294	3,800	3,800	8,094	3,800	2025
30	CODI: Corktown Substation	1,352	100	-	-	100	-	2023
31	CODI: Islandview Substation - Phase 1	12,255	7,734	7	-	7,741	-	2024
32	CODI: Islandview Substation - Phase 2	3,176	35,847	8,000	12,000	43,847	12,000	2025
33	CODI: Islandview Substation - Phase 3	45						2025
34	CODI: Midtown Substation Expansion	2,283	1,085	459	-	1,544	-	2024
35	CODI: Alfred Substation Expansion	63	3,183	18,235	2,715	21,418	2,715	2025
36	CODI: Howard Conversion	3						2025

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
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Schedule: B5.4
Witness: S. S. Deol
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(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	Capital Expenditures						
		Historical	Projected Calendar Year			Bridge Period	Test Year	In Service Year
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
37	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	241	737	2,537	-	3,274	-	2024
38	4.8 kV CC: Ariel Substation and Circuit Conversion	1,070	641	-	-	641	-	2023
39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade	13,401	2,174	-	-	2,174	-	2023
40	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade	2,043	4,204	1,311	-	5,515	-	2024
41	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	13,119	3,944	6,000	1,000	9,944	1,000	2025
42	4.8 kV CC: Buckler Circuit Conversion	8,889	3,882	3,922	-	7,804	-	2024
43	4.8 kV CC: McKinstry Sub Decommission	38	559	3,376	-	3,935	-	2024
44	4.8 kV CC: Quincy Conversion	1,052	1,667	1,692	-	3,360	-	2024
45	4.8 kV CC: Pinegrove Substation Relocation and Conversion	2,531	20,626	51,226	4,594	71,852	4,594	2025
46	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	-	95	(17,000)	(17,000)	(16,905)	(17,000)	2025
47	4.8 kV CC: Hawthorne Relief and Circuit Conversion	403	-	3,373	-	3,373	-	2024
48	4.8 kV CC: Crestwood Substation	25	640	-	-	640	-	2023
49	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	2,603	25	-	-	25	-	2023
50	4.8 kV CC: Power line Conversion of MADSN 175L-W	107	578	-	-	578	-	2023
51	4.8 kV CC: GRFIN & WMSTN Conversions	136	2,218	6,300	6,128	8,518	6,128	2025
52	4.8kV CC: SCOTN	50	1,174	1,885	-	3,059	-	2024
53	4.8 kV CC: Slater	1,930	4	-	-	4	-	2022
54	4.8 kV CC: Hilton Substation and Circuit Conversion	-	652	-	-	652	-	2023
55	4.8 kV CC: Curtis	-	17	2,174	-	2,191	-	2024
56	4.8 kV CC: Unionville DC 301 B1 Conversion	-	-	2,911	-	2,911	-	2024
57	System Loading: Brest Substation	(2)	-	-	-	-	-	2021
58	System Loading: Carleton	336	187	-	-	187	-	2023
59	System Loading: Grayling	-	-	-	-	-	-	2021
60	System Loading: Prospect	(146)	-	-	-	-	-	2021
61	System Loading: Mandy 307 Load Transfer	1	(82)	-	-	(82)	-	2022
62	System Loading: Mack Transformer 102	32	10	-	-	10	-	2023
63	System Loading: Globe	-	-	200	2,700	200	2,700	2025
64	Pilot: Strategic and Service Undergrounding	462	3,830	15,644	16,019	19,474	16,019	Annual
65	Pilot: Primary Deconductoring	1,846	36	-	-	36	-	2023
66	Subtransmission Redesign & Rebuild: Tie 810	8,832	21,771	13,000	15,920	34,771	15,920	2027
67	Subtransmission Redesign & Rebuild: Tie 7504	93	3,263	500	2,000	3,763	2,000	2029
68	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	896	-	-	-	-	-	2026
69	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	322	-	-	-	-	-	2026
70	Subtransmission Redesign & Rebuild: Trunk 2308	53	3,224	970	4,001	4,194	4,001	2028
71	Subtransmission Redesign & Rebuild: Tie 3205	96	791	-	4,000	791	4,000	2028
72	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	-	150	900	150	900	2028
73	Subtransmission Redesign & Rebuild: Tie 4104	134						2028
74	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	284	1,677	580	5,882	2,257	5,882	2026
75	Subtransmission Redesign & Rebuild: Trunk 4245	15	703	600	1,700	1,303	1,700	2027
76	Subtransmission Redesign & Rebuild: Trunk 4911	139						2027
77	Subtransmission Redesign & Rebuild: Custer Republic	-	-	-	-	-	-	2027
78	Subtransmission Redesign & Rebuild: Cortland Station Expansion	897	40	101	109	142	109	2026

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Infrastructure Redesign and Modernization
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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Capital Expenditures							
Line No.	Description	Historical	Projected Calendar Year			Bridge Period	Test Year	In Service Year	
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025		
79	CODI: CATO Substation Expansion	290	3,139	14,172	3,841	17,311	3,841	2027	
80	CODI: Garfield Radial (Midtown Circuits)	415	2,153	11,633	-	13,787	-	2026	
81	CODI: Garfield Network Upgrade	17,430	23,390	17,300	14,200	40,690	14,200	2026	
82	CODI: Kent/Gibson Conversion - Phase 1	2,186	8,845	15,107	-	23,951	-	2026	
83	4.8 kV CC: Zenon Substation and Circuit Conversion	1						2026	
84	4.8 kV CC: Calla Circuit Conversion and Phase 2	65						2026	
85	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	2,728	947	3,558	12,000	4,505	12,000	2027	
86	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	2	906	1,333	-	2,239	-	2030	
87	4.8 kV CC: ISO Conversion Program	52	6,466	1,700	-	8,166	-	2027	
88	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	-	152	750	1,400	902	1,400	2030	
89	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	0						2027	
90	8.3 kV CC: Pontiac Overhead Conversion	3,446	9,929	19,177	18,306	29,106	18,306	2028	
91	8.3 kV CC: Pontiac Underground Conversion	747	1,197	3,250	3,887	4,446	3,887	2026	
92	System Loading: Brown City	(28)	2,485	7,392	6,634	9,877	6,634	2026	
93	System Loading: Port Sanilac	15	438	2,389	9,246	2,827	9,246	2028	
94	System Loading: Richmond/Armada	3,201	8,417	8,893	6,152	17,310	6,152	2028	
95	System Loading: Cody	-	384	1,600	10,000	1,984	10,000	2030	
96	System Loading: Otsego/Capac/Shaw	-	151	88	1,617	239	1,617	2027	
97	System Loading: Macomb/Golf	-	-	-	126	-	126	2029	
98	System Loading: Grenada	225	3,521	6,535	12,000	10,056	12,000	2029	
99	System Loading: Lark/Spruce	14	24	1,350	4,045	1,375	4,045	2027	
100	System Loading: Jewell	-	1,265	592	364	1,857	364	2029	
101	System Loading: Mayville	-	-	-	150	-	150	2029	
102	System Loading: Goodison	-	-	-	79	-	79	2028	
103	System Loading: Wixom	-	72	2,033	7,000	2,105	7,000	2030	
104	System Loading: Diamond	-	-	21	231	21	231	2027	
105	System Loading: Spokane/Seneca	-	62	-	4,984	62	4,984	2028	
106	System Loading: Sterling	-	-	336	4,727	336	4,727	2028	
107	System Loading: Disco	-	75	417	2,372	492	2,372	2026	
108	System Loading: Tahoe	-	-	-	100	-	100	2028	
109	System Loading: New Baltimore/Chesterfield	-	-	250	2,345	250	2,345	2027	
110	System Loading: Kings Point	-	135	1,000	4,500	1,135	4,500	2030	
111	Total Infrastructure Redesign and Modernization Projects and Programs	173,059	259,244	291,496	227,003	550,740	227,003		
112	Category Summary								
113	Ann Arbor System Improvements (Sum lines 2 thru 4)	10,268	4,355	3,000	9,230	7,355	9,230		
114	Subtransmission Redesign and Rebuild (Sum lines 5 thru 27 and 66 thru 78)	52,352	71,946	40,603	43,627	112,549	43,627		
115	Conversions (Sum lines 28 thru 56 and 79 thru 91)	104,483	161,932	199,154	78,755	361,086	78,755		
116	System Loading (Sum lines 57 thru 63 and 92 thru 110)	3,648	17,145	33,095	79,371	50,240	79,371		
117	Pilots (Sum lines 64 thru 65)	2,308	3,866	15,644	16,019	19,510	16,019		
118	Total Infrastructure Redesign and Modernization Projects and Programs	173,059	259,244	291,496	227,003	550,740	227,003		

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: S. M. Hartwick
R. C. Steudle 1/
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(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Capital Expenditures						
Line No.	Description	Historical	Projected Calendar Year		Bridge Period		Test Year	In Service Year
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
1	Technology and Automation							
2	Distribution Automation	5,506	27,104	21,188	125,625	48,293	125,625	Annual
3	ADMS: DMS/OMS	28,961	9,270	-	-	9,270	-	2023
4	SOC: ESOC	1,250	-	-	-	-	-	2022
5	SOC: ASOC	7,534	20,927	-	-	20,927	-	2024
6	Grid Automation Telecommunications	16,328	21,346	16,900	15,000	38,246	15,000	Annual
7	Distribution Sensing and Monitoring (inclgd Line Sensors)	862	6,552	500	1,000	7,052	1,000	Annual
8	CVR/VVO	5,164	1,766	2,500	8,100	4,266	8,100	Annual
9	NWA: O'Shea Energy Storage	1,456	889	54	-	943	-	2024
10	NWA: Battery Trailer	2,051	1,191	2,250	-	3,441	-	2024
11	NWA: Omega Load Relief	4,464	2,454	27	-	2,481	-	2024
12	NWA: Fisher Load Relief	66	180	4,524	-	4,704	-	2024
13	NWA: Port Austin Load Relief	619	3,627	1,486	-	5,113	-	2024
14	NWA: Small Solar and Storage Testbed	335	400	565	500	965	500	2025
15	Sensor, Network and Algorithm Development (Solar Deployment)	218	1,058	200	200	1,258	200	2025
16	Technology Programs & NWA	0	1	-	-	1	-	2023
17	AMI: Meter Communications Upgrades	631	-	-	-	-	-	Annual
18	Customer Power Status Visibility	-	-	15,942	12,029	15,942	12,029	Annual
19	SCADA Remote Access and Configuration Platform	1,164	607	-	-	607	-	2023
20	Substation Reporting and Process Enhancements	-	-	200	-	200	-	2024
21	Asset Management Upgrades	1,711	2,121	-	-	2,121	-	2023
22	Systematic Tracking of Rotatable Assets	-	-	-	600	-	600	2025
23	External Crew Efficiency	-	-	4,407	800	4,407	800	2025
24	Tree Trim Risk Prioritization Model	1/ 3,078	3,824	-	-	3,824	-	2024
25	NWA: Veridian	360	1,832	2,646	4,287	4,478	4,287	2026
26	NWA: Adaptive Networked Microgrids	-	17	4,588	25,550	4,606	25,550	2027
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	-	(2,609)	(13,110)	(2,609)	(13,110)	2027
28	NWA: EV Charging Demonstration at ACM	1,292	1,292	920	2,500	2,212	2,500	2028
29	Interconnection Process Enablement	4,776	3,693	1,900	1,700	5,593	1,700	2028
30	Grid Edge Insights & New Technology	2,288	1,819	5,935	4,500	7,754	4,500	2028

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
(\$000)

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(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	Capital Expenditures						
		Historical	Projected Calendar Year			Bridge Period	Test Year	In Service Year
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	24 mos. ending 12/31/2024	12 mos. ending 12/31/2025	
31	DER Control	-	-	290	290	290	290	2028
32	ADMS Enhancements	-	-	7,000	7,000	7,000	7,000	2028
33	Operational Technology and Error Free Communication	5,496	136	5,600	1,400	5,736	1,400	2028
34	Meter Improvements	-	-	1,400	1,400	1,400	1,400	2028
35	FLISR Implementation	-	-	4,412	6,400	4,412	6,400	2028
36	DERMS	-	-	-	1,500	-	1,500	2028
37	Substation Cybersecurity	618	1,339	400	400	1,739	400	2028
38	Automation Configuration and Test Record Database	(115)	-	1,400	3,200	1,400	3,200	2026
39	Microwave End of Life	-	-	250	200	250	200	2028
40	Other Modernize Grid Management	7,807	26,411	2,200	2,500	28,611	2,500	2028
41	ADMS: Network Management System	2,071	1,998	1,600	2,800	3,598	2,800	2027
42	Load Forecasting & Analytics	2,737	2,841	3,900	4,600	6,741	4,600	2028
43	Hosting Capacity Enablement	108	253	350	300	603	300	2028
44	Power Quality Analysis Program	-	-	400	500	400	500	2028
45	Substation Design Tool Upgrades	552	597	1,250	1,200	1,847	1,200	2028
46	Distribution Planning	932	8,447	1,572	1,600	10,019	1,600	2026
47	Enhance Maximo Capabilities and Processes	-	-	-	500	-	500	2028
48	Primary Service Orders Replatform	-	-	2,000	4,100	2,000	4,100	2026
49	Work Management & Scheduling Upgrades	12,155	6,516	790	1,000	7,306	1,000	2026
50	Mobile tools expansion	-	-	1,100	800	1,100	800	2028
51	Maintain compliance	-	-	200	200	200	200	2028
52	Enhance and expand cybersecurity	-	-	300	800	300	800	2028
53	Mobile Equipment Replacement	-	-	881	2,800	881	2,800	2028
54	Mobile Technology	969	5,095	500	800	5,595	800	2028
55	Total Technology and Automation Projects and Programs	123,441	165,605	121,919	235,571	287,524	235,571	

1/ Tree Trim project sponsored by Company Witness R. C. Steudle

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Distribution Operations
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4
Witness: B. L. Hill 1/
M. Elliott Andahazy 2/
S. S. Deol 3/
S. M. Hartwick 4/
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(a)		(b)	(c)
Line No.	Description	Adjusted Historical 12 mos. ended 12/31/2022	Projected 12 mos. ending 12/31/2025
1	Base Capital Programs:		
2	Gordie Howe International Bridge 1/	-	-
3	Other Routine Base Capital Programs 1/	2,344	2,489 5/
4	Subtotal Base Capital Programs	2,344	2,489
5	Strategic Capital Programs:		
6	Infrastructure Resilience and Hardening 2/	2,893	2,588 5/
7	Infrastructure Redesign and Modernization:		
8	Ann Arbor System Improvements 3/	600	1,006
9	Other Infrastructure Redesign 3/	4,152	5,701 5/
10	Technology and Automation:		
11	SOC Modernization 4/	198	-
12	ADMS Projects 4/	2,965	-
13	Other Technology and Automation 4/	711	2,032 5/
14	Subtotal Strategic Capital Programs	11,518	11,327
15	Total AFUDC - Distribution Operations	13,862	13,816 6/

- 1/ Sponsored by Company Witness B. L. Hill: Base Capital Programs
2/ Sponsored by Company Witness M. Elliott Andahazy: Infrastructure Resilience and Hardening
3/ Sponsored by Company Witness S. S. Deol: Infrastructure Redesign and Modernization
4/ Sponsored by Company Witness S. M. Hartwick: Technology and Automation
5/ AFUDC estimates for platform are developed at a high level based on historical trend
6/ The projected AFUDC amounts are based on the authorized U-21297 of 5.561%

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
(\$000)

Case: U-21534
Exhibit: A-12
Schedule: B5.4
Witnesses: B. L. Hill 1/, M. Elliott Andahazy 2/,
S. S. Deol 3/, S.M. Hartwick 4/, R.C. Steudle 5/
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Line No.	(a) Description	(b) In-Service Assumption	(c) 12 mos. ended 12/31/2022	(d) 12 mos. ending 12/31/2023	(e) 12 mos. ending 12/31/2024	(f) 12 mos. ending 12/31/2025	(g) Est. % Removal	(h) 12 mos. ending 12/31/2023 <i>col (d)x(g)</i>	(i) 12 mos. ending 12/31/2024 <i>col (e)x(g)</i>	(j) 12 mos. ending 12/31/2025 <i>col (f)x(g)</i>	(k) 12 mos. ending 12/31/2023	(l) 12 mos. ending 12/31/2024	(m) 12 mos. ending 12/31/2025	(n) 12 mos. ending 12/31/2023 <i>col (d)-(h)-(k)</i>	(o) 12 mos. ending 12/31/2024 <i>col (e)-(i)-(l)</i>	(p) 12 mos. ending 12/31/2025 <i>col (f)-(j)-(m)</i>
			Capital Expenditures (including Removal Costs)					Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
Base Capital Programs																
1	Emergent Replacements	1/ Annual	484,722	531,257	492,578	506,851	15%	79,689	73,887	76,028	451,569	418,691	430,823	-	-	-
2	Connections & New Load:															
3	Gordie Howe International Bridge	1/ Dec-22	235	-	-	-	15%	-	-	-	-	-	-	-	-	-
4	I-375 Relocations	1/ Dec-25	-	5,938	25,000	8,000	15%	891	3,750	1,200	-	-	33,097	5,047	21,250	(26,297)
5	Other Connections and New Load	1/ Annual	296,239	294,980	278,216	292,848	15%	44,247	41,732	43,927	250,733	236,484	248,921	-	-	-
6	Connections Sub-Total		296,474	300,918	303,216	300,848		45,138	45,482	45,127	250,733	236,484	282,018	5,047	21,250	(26,297)
7																
8	Infrastructure Resilience and Hardening															
9	Mobile Fleet Program	2/ Annual	15,234	2,804	5,000	1,500	15%	421	750	225	2,383	4,250	1,275	-	-	-
10	Substation Risk: Drexel	2/ Dec-23	1,898	640	-	-	15%	96	-	-	2,158	-	-	(1,614)	-	-
11	Substation Risk: Chestnut	2/ Dec-25	64	989	2,725	7,881	15%	148	409	1,182	-	-	9,911	841	2,317	(3,212)
12	Substation Risk: Savage	2/ Jun-23	577	11	-	-	15%	2	-	-	500	-	-	(491)	-	-
13	Substation Risk: Apache	2/ Dec-24	4,653	8,492	3,810	-	15%	1,274	572	-	-	14,412	-	7,218	(11,173)	-
14	Substation Risk: Port Huron	2/ May-22	184	3	-	-	15%	0	-	-	3	-	-	-	-	-
15	Substation Risk: Belleville Switchgear Decomm	2/ Dec-23	1,234	1,313	-	-	15%	197	-	-	2,165	-	-	(1,048)	-	-
16	Substation Risk: McGraw	2/ Dec-24	12,699	6,310	37,852	-	15%	946	5,678	-	-	48,331	-	5,363	(16,157)	-
17	Substation Risk: Voyager	2/ Feb-23	201	2	-	-	15%	0	-	-	172	-	-	(171)	-	-
18	Substation Risk: Flood Defense Program	2/ Dec-24	87	269	5,009	-	15%	40	751	-	-	4,560	-	229	(303)	-
19	4.8 kV Hardening	2/ Annual	157,482	127,010	80,000	125,000	15%	19,052	12,000	18,750	107,959	68,000	106,250	-	-	-
20	Pole and Pole Top Maintenance and Modernize	2/ Annual	83,934	79,075	63,450	121,000	15%	11,861	9,518	18,150	67,214	53,933	102,850	-	-	-
21	Cable Replacement Program	2/ Annual	27,746	22,832	15,001	16,501	15%	3,425	2,250	2,475	19,407	12,751	14,026	-	-	-
22	Frequent Outage Program (CEMI)	2/ Annual	60,067	63,963	48,050	62,504	15%	9,595	7,207	9,376	54,369	40,842	53,128	-	-	-
23	Breaker Replacement Program	2/ Annual	14,415	13,161	-	-	15%	1,974	-	-	11,187	-	-	-	-	-
24	Pontiac Vaults	2/ Dec-23	1,263	657	-	-	15%	99	-	-	1,631	-	-	(1,073)	-	-
25	URD Replacement Program	2/ Annual	7,043	12,417	-	-	15%	1,863	-	-	10,554	-	-	-	-	-
26	URD Replacement Program: Detroit URD 1-1	2/ Dec-23	1,154	285	-	-	15%	43	-	-	1,224	-	-	(981)	-	-
27	40 kV: Automatic Pole Top Switch	2/ Annual	4,375	6,358	4,995	4,995	15%	954	749	749	5,404	4,246	4,246	-	-	-
28	Disconnect and Switcher Replacement	2/ Annual	4,182	15,457	4,900	4,900	15%	2,319	735	735	13,139	4,165	4,165	-	-	-
29	SCADA Pole Top Device Replacement	2/ Dec-35	764	1,694	1,808	2,038	15%	254	271	306	-	-	-	1,440	1,537	1,733
30	Substation Regulator Replacement	2/ Dec-27	685	1,337	816	822	15%	200	122	123	-	-	-	1,136	694	698
31	Steel Pole Highway Crossings	2/ Annual	1,880	1,734	5,000	5,000	15%	260	750	750	1,474	4,250	4,250	-	-	-
32	Station Upgrade: Warren (Relay Replacement)	2/ Dec-22	271	649	-	-	15%	97	-	-	552	-	-	-	-	-
33	Station Upgrade: Northeast (Relay Replacemer	2/ Dec-23	13,279	3,652	-	-	15%	548	-	-	14,391	-	-	(11,287)	-	-

Michigan Public Service Commission
DTE Electric Company
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Witnesses: B. L. Hill 1/, M. Elliott Andahazy 2/,
S. S. Deol 3/, S.M. Hartwick 4/, R.C. Steudle 5/
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Line No.	(a) Description	(b) In-Service Assumption	(c)	(d) Capital Expenditures (including Removal Costs)		(e)	(f)	(g) Est. % Removal	(h) Activity Accum. Depr. - Removal Costs			(i) Activity Plant in Service			(j) Activity CWIP - Net Additions/(Unitization)		
34	Substation Risk: Hood	2/	Dec-25	-	249	6,918	978	15%	37	1,038	147	-	-	6,923	211	5,881	(6,092)
35	Substation Risk: UNVIL 301 B1 Conversion	2/	Dec-23	-	112	-	-	15%	17	-	-	96	-	-	-	-	-
36	Portable Generators	1/	Dec-24	-	-	4,500	-	15%	-	675	-	-	3,825	-	-	-	-
37	Station Upgrade: Lincoln	2/	Dec-27	-	-	-	330	15%	-	-	50	-	-	-	-	-	281
38	Station Upgrade: Navarre	2/	Dec-26	-	-	330	5,300	15%	-	50	795	-	-	-	-	281	4,505
39	Station Upgrade: 120kV Relays Upgrade for IT(	2/	Dec-35	222	1,359	2,698	2,485	15%	204	405	373	-	-	-	1,155	2,293	2,112
40	Batteries and Chargers Replacement Program	2/	Annual	2,849	3,343	2,500	3,030	15%	501	375	454	2,841	2,125	2,575	-	-	-
41	Substation Risk: Savage Switchgear Replacem	2/	Dec-27	-	-	-	100	15%	-	-	15	-	-	-	-	-	85
42	Substation Risk: Seville	2/	Dec-27	-	-	-	243	15%	-	-	36	-	-	-	-	-	207
43	Substation Risk: Imlay	2/	Dec-30	-	-	-	100	15%	-	-	15	-	-	-	-	-	85
44	Resilience Sub-Total			418,440	376,177	295,363	364,706		56,427	44,304	54,706	318,822	265,690	309,599	928	(14,631)	401
45	Infrastructure Redesign																
46	Ann Arbor System Improvements: State Substation	3/	Dec-23	5,996	2,543	-	-	15%	382	-	-	7,259	-	-	(5,097)	-	-
47	Ann Arbor System Improvements: Apex (Blue) Substation	3/	Dec-23	3,484	1,478	-	-	15%	222	-	-	4,218	-	-	(2,962)	-	-
48	Ann Arbor System Improvements: Argo 40kV Reconfiguration	3/	Dec-24	787	334	3,000	9,230	15%	50	450	1,385	-	3,503	7,846	284	(953)	-
49	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	3/	Annual	1,947	2,477	4,745	4,736	15%	372	712	710	2,105	4,033	4,026	-	-	-
50	Subtransmission Redesign & Rebuild: Maxwell Amherst	3/	Dec-22	191	160	-	-	15%	24	-	-	136	-	-	-	-	-
51	Subtransmission Redesign & Rebuild: Tie 810 Subtransmission Redesign & Rebuild: Trunk	3/	Dec-27	8,832	21,771	13,000	15,920	15%	3,266	1,950	2,388	-	-	-	18,505	11,050	13,532
52	7106 Subtransmission Redesign & Rebuild: Trunk	3/	Dec-22	175	(90)	-	-	15%	(14)	-	-	(77)	-	-	-	-	-
53	2255 Subtransmission Redesign & Rebuild: Trunk	3/	Dec-23	2,473	698	-	-	15%	105	-	-	2,695	-	-	(2,102)	-	-
54	2237-ST Subtransmission Redesign & Rebuild: Trunk	3/	Dec-22	1,174	207	-	-	15%	31	-	-	176	-	-	-	-	-
55	7333 Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	3/	Dec-22	1,300	168	-	-	15%	25	-	-	142	-	-	-	-	-
56		3/	Dec-24	-	67	4,070	-	15%	10	610	-	-	3,516	-	57	(57)	-
57	Subtransmission Redesign & Rebuild: Boyne Subtransmission Redesign & Rebuild: Tie	3/	Dec-24	14,072	8,309	3,026	-	15%	1,246	454	-	-	21,596	-	7,063	(19,024)	-
58	7504 Subtransmission Redesign & Rebuild: Tie	3/	Dec-29	93	3,263	500	2,000	15%	489	75	300	-	-	-	2,773	425	1,700
59	4105 Phase 1 Subtransmission Redesign & Rebuild: Tie	3/	Dec-23	8,226	1,448	-	-	15%	217	-	-	8,223	-	-	(6,992)	-	-
60	4105 Phase 2 Subtransmission Redesign & Rebuild: Tie	3/	Dec-26	896	-	-	-	15%	-	-	-	-	-	-	-	-	-
61	4105 Phase 3 Subtransmission Redesign & Rebuild: Tie	3/	Dec-24	3,262	13,753	2,259	-	15%	2,063	339	-	-	16,383	-	11,690	(14,463)	-
62	4105 Phase 4 Subtransmission Redesign & Rebuild: Tie	3/	Dec-25	2,808	-	-	-	15%	-	-	-	-	-	2,387	-	-	(2,387)
63	4105 Phase 5 Subtransmission Redesign & Rebuild: Trunk	3/	Dec-26	322	-	-	-	15%	-	-	-	-	-	-	-	-	-
64	2308 Subtransmission Redesign & Rebuild: Tie	3/	Dec-28	53	3,224	970	4,001	15%	484	146	600	-	-	-	2,741	825	3,401
65	1568	3/	Dec-23	64	645	-	-	15%	97	-	-	603	-	-	(54)	-	-

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66	Subtransmission Redesign & Rebuild: Trunk 4217	3/	Dec-25	331	1,921	2,265	2,360	15%	288	340	354	-	-	5,845	1,633	1,925	(3,839)
67	Subtransmission Redesign & Rebuild: Trunk 3509	3/	Dec-24	126	2,284	3,653	-	15%	343	548	-	-	5,153	-	1,941	(2,048)	-
68	Subtransmission Redesign & Rebuild: Trunk 4266	3/	Dec-25	3	-	-	-	15%	-	-	-	-	-	2	-	-	(2)
69	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	3/	Dec-26	284	1,677	580	5,882	15%	252	87	882	-	-	-	1,426	493	5,000
70	Subtransmission Redesign & Rebuild: Trunk 4245	3/	Dec-27	15	703	600	1,700	15%	106	90	255	-	-	-	598	510	1,445
71	Subtransmission Redesign & Rebuild: Custer Republic	3/	Dec-27	-	-	-	-	15%	-	-	-	-	-	-	-	-	-
72	Subtransmission Redesign & Rebuild: Tie 3205	3/	Dec-28	96	791	-	4,000	15%	119	-	600	-	-	-	672	-	3,400
73	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	3/	Dec-28	-	-	150	900	15%	-	23	135	-	-	-	-	128	765
74	Subtransmission Redesign & Rebuild: Tie 4104	3/	Dec-28	134	-	-	-	15%	-	-	-	-	-	-	-	-	-
75	Subtransmission Redesign & Rebuild: Trunk 4911	3/	Dec-27	139	-	-	-	15%	-	-	-	-	-	-	-	-	-
76	Subtransmission Redesign & Rebuild: Praxair	3/	Dec-25	-	-	565	2,000	15%	-	85	300	-	-	2,180	-	480	(480)
77	Subtransmission Redesign & Rebuild: Small Projects & Reserve	3/	Dec-24	-	4	500	-	15%	1	75	-	-	428	-	3	(3)	-
78	Subtransmission Breaker Short Circuit Violations	3/	Dec-24	1,645	2,864	50	-	15%	430	8	-	-	3,875	-	2,434	(3,833)	-
79	Subtransmission Redesign & Rebuild: Slocum	3/	Dec-23	125	511	-	-	15%	77	-	-	541	-	-	(107)	-	-
80	Subtransmission Redesign & Rebuild: Cortland Station Expansion	3/	Dec-26	897	40	101	109	15%	6	15	16	-	-	-	34	86	92
81	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	3/	Dec-24	2,670	2,717	260	-	15%	408	39	-	-	4,800	-	2,309	(4,579)	-
82	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	3/	Dec-25	-	-	-	-	15%	-	-	-	-	-	-	-	-	-
83	TCHPP Switchyard Upgrades	3/	Dec-25	-	2,334	3,309	20	15%	350	496	3	-	-	4,813	1,984	2,812	(4,796)
84	Trunk and Tie Lines Hardening Program: Prior Year's	3/	Dec-22	(2)	-	-	-	15%	-	-	-	-	-	-	-	-	-
85	CODI: Charlotte Network Upgrade	3/	Dec-25	8,319	8,727	10,967	11,884	15%	1,309	1,645	1,783	-	-	33,911	7,418	9,322	(23,810)
86	CODI: Targeted Network Secondary Cable Replacement	3/	Dec-25	1,987	4,294	3,800	3,800	15%	644	570	570	-	-	11,799	3,650	3,230	(8,569)
87	CODI: Corktown Substation	3/	Dec-23	1,352	100	-	-	15%	15	-	-	1,235	-	-	(1,150)	-	-
88	CODI: Islandview Substation - Phase 1	3/	Dec-24	12,255	7,734	7	-	15%	1,160	1	-	-	16,997	-	6,574	(16,991)	-
89	CODI: Islandview Substation - Phase 2	3/	Dec-25	3,176	35,847	8,000	12,000	15%	5,377	1,200	1,800	-	-	50,170	30,470	6,800	(39,970)
90	CODI: Islandview Substation - Phase 3	3/	12/1/2025	45	-	-	-	15%	-	-	-	-	-	-	-	-	-
91	CODI: CATO Substation Expansion	3/	Dec-27	290	3,139	14,172	3,841	15%	471	2,126	576	-	-	-	2,668	12,046	3,265
92	CODI: Garfield Radial (Midtown Circuits)	3/	Dec-26	415	2,153	11,633	-	15%	323	1,745	-	-	-	-	1,830	9,888	-
93	CODI: Midtown Substation Expansion	3/	Dec-24	2,283	1,085	459	-	15%	163	69	-	-	3,253	-	923	(2,863)	-
94	CODI: Alfred Substation Expansion	3/	Dec-25	63	3,183	18,235	2,715	15%	477	2,735	407	-	-	20,566	2,705	15,500	(18,258)
95	CODI: Howard Conversion	3/	12/1/2025	3	-	-	-	15%	-	-	-	-	-	-	-	-	-
96	CODI: Garfield Network Upgrade	3/	Dec-26	17,430	23,390	17,300	14,200	15%	3,508	2,595	2,130	-	-	-	19,881	14,705	12,070
97	CODI: Kent/Gibson Conversion - Phase 1	3/	Dec-26	2,186	8,845	15,107	-	15%	1,327	2,266	-	-	-	-	7,518	12,841	-
98	4.8 kV CC: Zenon Substation and Circuit Conversion	3/	Dec-26	1	-	-	-	15%	-	-	-	-	-	-	-	-	-

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Line No.	Description	In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal		Activity Accum. Depr. - Removal Costs			Activity Plant in Service		CWIP - Net Additions/(Unitization)		
99	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	3/ Dec-24	241	737	2,537	-	15%	111	381	-	-	2,987	-	627	(831)	-
100	4.8 kV CC: Ariel Substation and Circuit Conversion	3/ Dec-23	1,070	641	-	-	15%	96	-	-	1,454	-	-	(909)	-	-
101	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade	3/ Dec-23	13,401	2,174	-	-	15%	326	-	-	13,238	-	-	(11,391)	-	-
102	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	3/ Dec-25	13,119	3,944	6,000	1,000	15%	592	900	150	-	-	20,454	3,353	5,100	(19,604)
103	4.8 kV CC: Buckler Circuit Conversion	3/ Dec-24	8,889	3,882	3,922	-	15%	582	588	-	-	14,189	-	3,300	(10,856)	-
104	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	3/ Dec-27	2,728	947	3,558	12,000	15%	142	534	1,800	-	-	-	805	3,024	10,200
105	4.8 kV CC: McKinstry Sub Decommission	3/ Dec-24	38	559	3,376	-	15%	84	506	-	-	3,377	-	475	(507)	-
106	4.8 kV CC: Quincy Conversion	3/ Dec-24	1,052	1,667	1,692	-	15%	250	254	-	-	3,750	-	1,417	(2,311)	-
107	4.8 kV CC: Pinegrove Substation Relocation and Conversion	3/ Dec-25	2,531	20,626	51,226	4,594	15%	3,094	7,684	689	-	-	67,130	17,532	43,542	(63,225)
108	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	3/ Dec-25	-	95	(17,000)	(17,000)	15%	14	(2,550)	(2,550)	-	-	(28,819)	81	(14,450)	14,369
109	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade	3/ Dec-24	2,043	4,204	1,311	-	15%	631	197	-	-	6,424	-	3,574	(5,310)	-
110	4.8 kV CC: Calla Circuit Conversion and Phase 2	3/ Dec-26	65	-	-	-	15%	-	-	-	-	-	-	-	-	-
111	4.8 kV CC: Hawthorne Relief and Circuit Conversion	3/ Dec-24	403	-	3,373	-	15%	-	506	-	-	3,210	-	-	(343)	-
112	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	3/ Dec-30	2	906	1,333	-	15%	136	200	-	-	-	-	770	1,133	-
113	4.8 kV CC: Crestwood Substation	3/ Dec-23	25	640	-	-	15%	96	-	-	565	-	-	(21)	-	-
114	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	3/ Dec-23	2,603	25	-	-	15%	4	-	-	2,233	-	-	(2,212)	-	-
115	4.8 kV CC: Power line Conversion of MADSN 175L-W	3/ Dec-23	107	578	-	-	15%	87	-	-	582	-	-	(91)	-	-
116	4.8 kV CC: GRFIN & WMSTN Conversions	3/ Dec-25	136	2,218	6,300	6,128	15%	333	945	919	-	-	12,564	1,885	5,355	(7,355)
117	4.8 kV CC: ISO Conversion Program	3/ Dec-27	52	6,466	1,700	-	15%	970	255	-	-	-	-	5,496	1,445	-
118	4.8kV CC: SCOTN	3/ Dec-24	50	1,174	1,885	-	15%	176	283	-	-	2,643	-	998	(1,041)	-
119	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	3/ Dec-30	-	152	750	1,400	15%	23	113	210	-	-	-	130	638	1,190
120	4.8 kV CC: Slater	3/ Dec-22	1,930	4	-	-	15%	1	-	-	3	-	-	-	-	-
121	4.8 kV CC: Curtis	3/ Dec-24	-	17	2,174	-	15%	3	326	-	-	1,863	-	15	(15)	-
122	4.8 kV CC: Unionville DC 301 B1 Conversion	3/ Dec-24	-	-	2,911	-	15%	-	437	-	-	2,474	-	-	(0)	-
123	4.8 kV CC: Hilton Substation and Circuit Conversion	3/ Dec-23	-	652	-	-	15%	98	-	-	554	-	-	-	-	-
124	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	3/ Dec-27	0	-	-	-	15%	-	-	-	-	-	-	-	-	-
125	8.3 kV CC: Pontiac Overhead Conversion	3/ Dec-28	3,446	9,929	19,177	18,306	15%	1,489	2,877	2,746	-	-	-	8,440	16,300	15,560
126	8.3 kV CC: Pontiac Underground Conversion	3/ Dec-26	747	1,197	3,250	3,887	15%	180	487	583	-	-	-	1,017	2,762	3,304
127	System Loading: Brest Substation	3/ Dec-21	(2)	-	-	-	15%	-	-	-	-	-	-	-	-	-
128	System Loading: Carleton	3/ Dec-23	336	187	-	-	15%	28	-	-	445	-	-	(286)	-	-
129	System Loading: Grayling	3/ Dec-21	-	-	-	-	15%	-	-	-	-	-	-	-	-	-
130	System Loading: Prospect	3/ Dec-21	(146)	-	-	-	15%	-	-	-	-	-	-	-	-	-
131	System Loading: Mandy 307 Load Transfer	3/ Dec-22	1	(82)	-	-	15%	(12)	-	-	(70)	-	-	-	-	-

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132	System Loading: Brown City	3/	Dec-26	(28)	2,485	7,392	6,634	15%	373	1,109	995	-	-	-	2,112	6,283	5,639
133	System Loading: Mack Transformer 102	3/	Dec-23	32	10	-	-	15%	1	-	-	35	-	-	(27)	-	-
134	System Loading: Port Sanilac	3/	Dec-28	15	438	2,389	9,246	15%	66	358	1,387	-	-	-	372	2,031	7,859
135	System Loading: Richmond/Armada	3/	Dec-28	3,201	8,417	8,893	6,152	15%	1,263	1,334	923	-	-	-	7,154	7,559	5,229
136	System Loading: Cody	3/	Dec-30	-	384	1,600	10,000	15%	58	240	1,500	-	-	-	326	1,360	8,500
137	System Loading: Otsego/Capac/Shaw	3/	Dec-27	-	151	88	1,617	15%	23	13	243	-	-	-	129	75	1,375
138	System Loading: Macomb/Golf	3/	Dec-29	-	-	-	126	15%	-	-	19	-	-	-	-	-	107
139	System Loading: Grenada	3/	Dec-29	225	3,521	6,535	12,000	15%	528	980	1,800	-	-	-	2,993	5,555	10,200
140	System Loading: Lark/Spruce	3/	Dec-27	14	24	1,350	4,045	15%	4	203	607	-	-	-	21	1,148	3,438
141	System Loading: Globe	3/	Dec-25	-	-	200	2,700	15%	-	30	405	-	-	2,465	-	170	(170)
142	System Loading: Jewell	3/	Dec-29	-	1,265	592	364	15%	190	89	55	-	-	-	1,076	503	309
143	System Loading: Mayville	3/	Dec-29	-	-	-	150	15%	-	-	23	-	-	-	-	-	128
144	System Loading: Goodison	3/	Dec-28	-	-	-	79	15%	-	-	12	-	-	-	-	-	67
145	System Loading: Wixom	3/	Dec-30	-	72	2,033	7,000	15%	11	305	1,050	-	-	-	61	1,728	5,950
146	System Loading: Diamond	3/	Dec-27	-	-	21	231	15%	-	3	35	-	-	-	-	18	196
147	System Loading: Spokane/Seneca	3/	Dec-28	-	62	-	4,984	15%	9	-	748	-	-	-	53	-	4,237
148	System Loading: Sterling	3/	Dec-28	-	-	336	4,727	15%	-	50	709	-	-	-	-	286	4,018
149	System Loading: Disco	3/	Dec-26	-	75	417	2,372	15%	11	63	356	-	-	-	64	354	2,016
150	System Loading: Tahoe	3/	Dec-28	-	-	-	100	15%	-	-	15	-	-	-	-	-	85
151	System Loading: New Baltimore/Chesterfield	3/	Dec-27	-	-	250	2,345	15%	-	38	352	-	-	-	-	213	1,993
152	System Loading: Kings Point	3/	Dec-30	-	135	1,000	4,500	15%	20	150	675	-	-	-	115	850	3,825
153	Pilot: Strategic and Service Undergrounding	3/	Annual	462	3,830	15,644	16,019	15%	575	2,347	2,403	3,256	13,297	13,616	-	-	-
154	Pilot: Primary Deconductoring	3/	Dec-23	1,846	36	-	-	15%	5	-	-	1,600	-	-	(1,569)	-	-
155	Redesign Sub-Total	3/		173,059	259,244	291,496	227,003		38,887	43,724	34,050	51,153	137,753	230,955	169,205	110,018	(38,003)
156																	
157	Technology and Automation																
158	ADMS: DMS/OMS	4/	Feb-23	28,961	9,270	-	-	0%	-	-	-	38,231	-	-	(28,961)	-	-
159	ADMS: Network Management System	4/	Dec-27	2,071	1,998	1,600	2,800	0%	-	-	-	-	-	-	1,998	1,600	2,800
160	ADMS Enhancements	4/	Dec-28	-	-	7,000	7,000	0%	-	-	-	-	-	-	-	7,000	7,000
161	Meter Improvements	4/	Dec-28	-	-	1,400	1,400	0%	-	-	-	-	-	-	-	1,400	1,400
162	FLISR Implementation	4/	Dec-28	-	-	4,412	6,400	0%	-	-	-	-	-	-	-	4,412	6,400
163	SOC: ESOC	4/	Dec-22	1,250	-	-	-	0%	-	-	-	-	-	-	-	-	-
164	SOC: ASOC	4/	May-24	7,534	20,927	-	-	0%	-	-	-	-	28,461	-	20,927	(28,461)	-

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
(\$000)

Case: U-21534
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S. S. Deol 3/, S.M. Hartwick 4/, R.C. Steudle 5/
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
Line No.	Description	In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)			
165	Grid Automation Telecommunications Distribution Sensing and Monitoring (inclgd Line Sensors)	4/	Annual	16,328	21,346	16,900	15,000	0%	-	-	-	21,346	16,900	15,000	-	-	-
166		4/	Annual	862	6,552	500	1,000	0%	-	-	-	6,552	500	1,000	-	-	-
167	Tree Trim Risk Prioritization Model	5/	Dec-24	3,078	3,824	-	-	0%	-	-	-	-	6,902	-	3,824	(6,902)	-
168	Distribution Automation	4/	Annual	5,506	27,104	21,188	125,625	0%	-	-	-	27,104	21,188	125,625	-	-	-
169	CVR/VVO	4/	Annual	5,164	1,766	2,500	8,100	0%	-	-	-	1,766	2,500	8,100	-	-	-
170	NWA: O'Shea Energy Storage	4/	Dec-24	1,456	889	54	-	0%	-	-	-	-	2,399	-	889	(2,345)	-
171	NWA: Battery Trailer	4/	Dec-24	2,051	1,191	2,250	-	0%	-	-	-	-	5,492	-	1,191	(3,242)	-
172	NWA: Omega Load Relief	4/	Dec-24	4,464	2,454	27	-	0%	-	-	-	-	6,945	-	2,454	(6,918)	-
173	NWA: Fisher Load Relief	4/	Dec-24	66	180	4,524	-	0%	-	-	-	-	4,770	-	180	(246)	-
174	NWA: Port Austin Load Relief	4/	Dec-24	619	3,627	1,486	-	0%	-	-	-	-	5,732	-	3,627	(4,246)	-
175	NWA: Veridian	4/	Dec-26	360	1,832	2,646	4,287	0%	-	-	-	-	-	-	1,832	2,646	4,287
176	NWA: Small Solar and Storage Testbed	4/	Dec-25	335	400	565	500	0%	-	-	-	-	-	1,800	400	565	(1,300)
177	NWA: EV Charging Demonstration at ACM	4/	Dec-28	1,292	1,292	920	2,500	0%	-	-	-	-	-	-	1,292	920	2,500
178	NWA: Adaptive Networked Microgrids	4/	Dec-27	-	17	4,588	25,550	0%	-	-	-	-	-	-	17	4,588	25,550
179	NWA: Adaptive Networked Microgrids - Project Contributions	4/	Dec-27	-	-	(2,609)	(13,110)	0%	-	-	-	-	-	-	-	(2,609)	(13,110)
180	Technology Programs & NWA	4/	Dec-23	0	1	-	-	0%	-	-	-	1	-	-	(0)	-	-
181	DERMS	4/	Dec-28	-	-	-	1,500	0%	-	-	-	-	-	-	-	-	1,500
182	DER Control	4/	Dec-28	-	-	290	290	0%	-	-	-	-	-	-	-	290	290
183	Mobile Technology	4/	Dec-28	969	5,095	500	800	0%	-	-	-	-	-	-	5,095	500	800
184	Power Quality Analysis Program	4/	Dec-28	-	-	400	500	0%	-	-	-	-	-	-	-	400	500
185	Distribution Planning	4/	Dec-26	932	8,447	1,572	1,600	0%	-	-	-	-	-	-	8,447	1,572	1,600
186	Enhance Maximo Capabilities and Processes	4/	Dec-28	-	-	-	500	0%	-	-	-	-	-	-	-	-	500
187	Primary Service Orders Replatform	4/	Dec-26	-	-	2,000	4,100	0%	-	-	-	-	-	-	-	2,000	4,100
188	External Crew Efficiency	4/	Dec-25	-	-	4,407	800	0%	-	-	-	-	-	5,207	-	4,407	(4,407)
189	Work Management & Scheduling Upgrades	4/	Dec-26	12,155	6,516	790	1,000	0%	-	-	-	-	-	-	6,516	790	1,000
190	Substation Design Tool Upgrades	4/	Dec-28	552	597	1,250	1,200	0%	-	-	-	-	-	-	597	1,250	1,200
191	Asset Management Upgrades	4/	Dec-23	1,711	2,121	-	-	0%	-	-	-	3,832	-	-	(1,711)	-	-
192	Load Forecasting & Analytics	4/	Dec-28	2,737	2,841	3,900	4,600	0%	-	-	-	-	-	-	2,841	3,900	4,600
193	Interconnection Process Enablement	4/	Dec-28	4,776	3,693	1,900	1,700	0%	-	-	-	-	-	-	3,693	1,900	1,700
194	Hosting Capacity Enablement	4/	Dec-28	108	253	350	300	0%	-	-	-	-	-	-	253	350	300
195	AMI: Meter Communications Upgrades	4/	Annual	631	-	-	-	0%	-	-	-	-	-	-	-	-	-
196	Microwave End of Life	4/	Dec-28	-	-	250	200	0%	-	-	-	-	-	-	-	250	200
197	SCADA Remote Access and Configuration Platform	4/	Dec-23	1,164	607	-	-	0%	-	-	-	1,771	-	-	(1,164)	-	-

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description	In-Service Assumption	Capital Expenditures (including Removal Costs)				Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
198	Automation Configuration and Test Record Database	4/ Dec-26	(115)	-	1,400	3,200	0%	-	-	-	-	-	-	-	1,400	3,200
199	Grid Edge Insights & New Technology Sensor, Network and Algorithm Development	4/ Dec-28	2,288	1,819	5,935	4,500	0%	-	-	-	-	-	-	1,819	5,935	4,500
200	(Solar Deployment)	4/ Dec-25	218	1,058	200	200	0%	-	-	-	-	-	1,676	1,058	200	(1,476)
201	Other Modernize Grid Management	4/ Dec-28	7,807	26,411	2,200	2,500	0%	-	-	-	-	-	-	26,411	2,200	2,500
202	Mobile tools expansion	4/ Dec-28	-	-	1,100	800	0%	-	-	-	-	-	-	-	1,100	800
203	Maintain compliance	4/ Dec-28	-	-	200	200	0%	-	-	-	-	-	-	-	200	200
204	Enhance and expand cybersecurity	4/ Dec-28	-	-	300	800	0%	-	-	-	-	-	-	-	300	800
205	Customer Power Status Visibility	4/ Annual	-	-	15,942	12,029	0%	-	-	-	-	15,942	12,029	-	-	-
206	Mobile Equipment Replacement	4/ Dec-28	-	-	881	2,800	0%	-	-	-	-	-	-	-	881	2,800
207	Substation Cybersecurity	4/ Dec-28	618	1,339	400	400	0%	-	-	-	-	-	-	1,339	400	400
208	Operational Technology and Error Free Communication	4/ Dec-28	5,496	136	5,600	1,400	0%	-	-	-	-	-	-	136	5,600	1,400
209	Substation Reporting and Process Enhancements	4/ Dec-24	-	-	200	-	0%	-	-	-	-	200	-	-	-	-
210	Systematic Tracking of Rotatable Assets	4/ Dec-25	-	-	-	600	0%	-	-	-	-	-	600	-	-	-
211	Technology Sub-Total		123,441	165,605	121,919	235,571		-	-	-	100,604	117,931	171,036	65,001	3,989	64,535
212																
213	Total Distribution Plant		1,496,136	1,633,201	1,504,572	1,634,979		220,139	207,398	209,911	1,172,880	1,176,548	1,424,432	240,181	120,625	636

1/ Sponsored by Company Witness B. L. Hill: Base Capital Programs
2/ Sponsored by Company Witness M. Elliott Andahazy: Infrastructure Resilience and Hardening
3/ Sponsored by Company Witness S. S. Deol: Infrastructure Redesign
4/ Sponsored by Company Witness S.M. Hartwick: Technology and Automation
5/ Sponsored by Company Witness R.C. Steudle: Tree Trim project

DTE Pilot Informational Document

Project Name: NWA: O’Shea Energy Storage
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• The 2MW solar array on Chicago 1415 is potentially causing power quality issues • Solar generation frequently exceeds the circuit load and power flows back through the substation • During periods where solar generation is intermittent or changing rapidly, customers near the solar array may be experiencing over voltage issues or flicker, leading to complaints or reduced lifetime of utility equipment
b. Pilot goals and desired learnings are detailed	Pilot Goals: • Addressing circuit power quality issues due to the solar array • The installation of a 1MW (1hr) Battery Energy Storage System (ESS) interconnected at the O’Shea Solar Site will address the voltage issues. • Implement BESS system • Wholesale market participation test bed for FERC order 841 Lessons learned: • Create standard designs, operations and maintenance instructions of battery storage system for the Company • Processes and practices for interconnecting battery systems at renewable sites
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	• The pilot has two primary components: ○ Defer traditional capital investment ○ Provide load relief utilizing NWA technologies • Pilot design and evaluation were presented in MPSC Case No. U-20147 filed on September 30, 2021
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	N/A
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	Statistical analysis will not be conducted
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	See (2) a. above

(3) Pilot project costs detailed					
a. Project costs are detailed by source and amount for all applicable periods		2021	2022	2023	2024
	Contract Labor	\$334,791	\$690,587	\$296,877	
	DTE Labor	\$15,400	\$93,154	\$184,128	\$23,188
	Material	\$247,573	\$158,465	\$155,218	\$17,672
	Design	\$50,987			
	Engineering	\$57,123	\$8,129		
	Overheads	\$389,653	\$505,404	\$252,800	\$14,000
	Total	\$1,095,527	\$1,455,739	\$889,023	\$54,860
Below are the highest cost items for the categories mentioned above: <u>Contract Labor</u>¹: \$390K - Construct BESS Below Grade Phase 1 \$360K – Installation of battery \$226K – Vendor cost to perform system integration \$114K – Installation of additional equipment \$50K – Site design work <u>DTE Labor</u>: \$64K – DTE support to construct BESS Below Grade Phase 1 \$68K – DTE facilitate system integration <u>Material</u>: \$167K – Cost to implement BESS (below grade, foundation for equipment, electrical infrastructure installation) \$116K – Additional switches needed, PM123 & PMH – 9 (Not included in original scope) \$100K – Additional battery cost \$86K – Design changes due to concrete encased conduit and global inflation \$53K – Miscellaneous					
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	No non-utility funding available				

¹ Contract labor services are bid out on competitive RFPs on a regular basis. These contracts contain fixed labor and equipment rates, and unit pricing for the duration of the contract. At the end of the contract term, DTE enters another RFP event to test the market competitiveness

c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA solution is a pilot to assess if this technology is cost effective compared to traditional substation and equipment upgrades, that would be required to address the power quality issues in the area. Cost associated with NWA solution to address voltage issues is competitively bid to get the best possible price in the industry.
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• 2022: ○ Below grade work at site – Completed ○ Concrete support pads on site – Completed ○ Site ready to install battery – Completed • 2023 ○ Installation of communication and fire alarm system • 2024: ○ Construction completion and commissioning ○ Installation of Viper recloser

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	• Engage communities on the permitting and approval process for siting batteries – City of Detroit permit received in April 2022 • Partner with MPSC Staff for pilot review
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	Not yet determined, the project is projected to be complete in 2023

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	New technologies such batteries are becoming available for utilities to use to solve traditional electrical system concerns. Using this new technology and integrating them with power generation strategies are opportunities to defer traditional investment to future years.

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, shared.	N/A
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Provide benefit to customers by deferring more costly traditional reconductoring and voltage regulation projects
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service and equipment providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	Provide benefit to customers by deferring more costly traditional reconductoring and voltage regulation projects in densely and low-income areas in the City of Detroit
f. Any other public benefits detailed.	N/A

DTE Pilot Informational Document

Project Name: NWA: Battery Trailer
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• Temporary installation of mobile batteries during an extended-unplanned power outages resulting in faster restoration time. The mobile batteries can be used in planned outages to supply power to reduce customers affected. • Develop documentation and required operating procedures to deploy the mobile battery in the field for temporary installations • Develop control, protection, and security requirements for mobile storage
b. Pilot goals and desired learnings are detailed	The main objectives of the pilot are as follows: • The use of battery trailers will be used to address issues such as overloads and reduce risk in operating contingency plans as opposed to using traditional portable generators, • Supporting system needs during shutdowns or maintenance, deploy at substations or on circuits to reduce peak load as part of a broader NWA initiative • Deployment costs, time, and challenges; operating processes; procedures; and staffing
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	Measures will include the following: • Demand impact compared to expectation • Deployment time • Deployment costs • Reliability impact compared to expectation

b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Not applicable plan, the Company has identified one customer. The Company is confident that a second participant will be.
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	See (2) a. above
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	Specific statistical analyses will not be conducted, but DTE will be collecting and tracking a variety of metrics to measure: • Demand impact compared to expectation • Deployment time • Deployment costs • Reliability impact compared to expectation

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	• 2022 - \$949K • 2023 - \$750K • 2023 - \$2,250K • 2024 - \$2,250K Cost of Battery trailer: \$2.22M Mobile Battery trailer and other large equipment purchases are bid out on competitive RFPs (Request for Proposal). The company is standardizing equipment & materials which can provide economy of scale purchases
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	No non-utility funding available
c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA solution is a pilot to assess if this technology is cost effective compared to our traditional restoration methods. Mobile battery can be readily available and be easily moved to be used at locations with unplanned outages reducing the restoration time for customers.

d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• 2021 – Engineering design and procurement - Complete • 2022 – Equipment delivery, testing and engineering - Complete • 2023 and 2024 – Complete construction and commission

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	Partner with Staff for pilot review
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	N/A

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	• Utilize the new storage technology to integrate distributed energy resources • Reduce emissions compared to the use of traditional portable diesel generators
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, shared.	New technologies such as batteries are becoming available for utilities to use to solve traditional electrical system concerns. Using these new tools and integrating them with power generation strategies are opportunities
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Utilize storage as targeted resiliency and reliability for emergent issues of temporary duration

Case No.: U-21534

Exhibit: A-12

Schedule B5.4.2

Witness: S.M. Hartwick

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d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	Reduce emissions compared to the use of traditional portable diesel generators in communities of vulnerable populations
f. Any other public benefits detailed.	N/A

DTE Pilot Informational Document

Project Name: NWA: Omega Load Relief
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• In 2020, two subtransmission lines had more than 1000 blocking hours which poses risk of customer outages • Omega substation is over firm • High load growth in the area due to indoor agriculture
b. Pilot goals and desired learnings are detailed	Pilot Goals: • Effectiveness of battery/energy storage at reducing blocking hours • Refine battery storage evaluation tool • Control, protection, and security requirements for storage • Deployment costs, time, and challenges • Operating processes, procedures, and staffing Lessons learned: • The Company has learned technical specifications and requirements to integrate battery storage equipment with the electrical system in a safe and reliable manner. The pilot resulted in developing standards to use this technology for similar applications. • Have a make ready battery system for future deployments, that is commercially available and integrates utility operating equipment and controls. • Global supply chain issues contributed to extended lead times and increase in material and shipping cost, which delayed the timeline of the project and increased pilot cost • Benchmark other utilities to further develop standards which will reduce the time and cost to interface the battery with the company's system.

c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	- Pilot design and evaluation were presented in MPSC Case No. U-20147 filed on September 30, 2021 - Measures will include the following: - Demand impact compared to expectation - Deployment time - Deployment costs - Reliability impact compared to expectation
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Selected Omega substation based on high load growth area and the potential to use battery storage as an NWA solution to provide load relief
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	See (2) d. below
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	Specific statistical analysis will not be conducted, but DTE will be collecting and tracking a variety of metrics to measure: - Demand impact compared to expectation - Deployment time - Deployment costs - Reliability impact compared to expectation The Company has gained knowledge of the requirements and specifications needed to integrate battery storage equipment safely and effectively with the electrical system. The pilot led to the creation of standards for using this technology in related applications.

(3) Pilot project costs detailed

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

	2021	2022	2023
Contract Labor	\$526,187	\$139,548	\$400,000
DTE Labor	\$101,132	\$249,012	\$239,000
Material	\$4,090,884	\$3,548,304	\$1,395,890
Design		\$22,917	
Engineering	\$31,510	\$5,435	
Overheads	\$795,529	\$564,033	\$420,055
Total	\$5,545,242	\$4,464,000	\$2,454,000

Below are the highest cost items for the categories mentioned above:

Contract Labor¹:

\$101K – Design services
\$300K - Construction underground
\$72K – Construction overhead
\$41K – Consultation services from vendor
\$200K - Additional cost due to delay in delivery of the battery trailer and in-commissioning of battery
\$115K – Miscellaneous

DTE Labor:

\$241K – Substation work including operators, relay techs, PERT techs, SCADA techs
\$79K – Underground cable construction
\$25K – Overhead construction
\$10K – Underground conduit construction

Material²:

\$5,504K – Mobile Battery trailer – including all components from battery manufacturer facility and integrator facility, and duties/tariffs
\$214K – Cable and conduit material
\$116K - Miscellaneous

¹ Contract labor services are bid out on competitive RFPs on a regular basis. These contracts contain fixed labor and equipment rates, and unit pricing for the duration of the contract. At the end of the contract term, DTE enters another RFP event to test the market competitiveness

² Mobile Battery trailer and other large equipment purchases are bid out on competitive RFPs (Request for Proposal). The company is standardizing equipment & materials which can provide economy of scale purchases

b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	No non-utility funding available
c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA solution is a pilot to assess if this technology can be deployed more rapidly and with lower costs compared to traditional solutions such as substation upgrades and circuits conversions to address the over firm substation
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• 2022: ○ Construction for the battery site – Complete ○ Standard for future storage applications – Complete 2023 • 2023: ○ Delay in delivery of the Battery trailer system by the vendor. The delays were a result of issue with the Fire monitoring system. These issues extended lead times and increased material and shipping costs. The engineering team explored alternate materials to meet the original project timeline created by the lead time issues. Although the project was extended into 2024 the team was able to mitigate further schedule challenges; however, this did result in additional costs from the original forecast. • 2024 ○ Construction completion and commissioning of the battery trailer system

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	Partner with MPSC Staff for pilot review

b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	N/A

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	New technologies such batteries are becoming available for utilities to use to solve traditional electrical system concerns. Using this new technology and integrating them with power generation strategies are opportunities to defer traditional investment to future years.
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, shared.	N/A
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Provide benefit by increasing system reliability
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service and equipment providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	See (6)c.
f. Any other public benefits detailed.	N/A

DTE Pilot Informational Document

Project Name: NWA: Fisher
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	- Fisher substation is over its firm rating by approximately 2.5MVA. In addition, two circuits served by Fisher are over or expected to be over the 8MVA design standard for 13.2kV circuits - The Fisher pilot expands upon the scope of the Hancock pilot by incorporating geo-targeted demand response (DR) into the portfolio of programs - Fisher substation pilot project will leverage several findings from the Hancock substation cost benefit model that exceeded the peak saving goals. - Leveraged the existing EWR HVAC, Appliance Recycling, HES, and DTE Marketplace programs to exceed the forecasted goal by 5.04 kW, achieving 139% of residential goal - Field test achieved 143% of the C&I kW impact reduction target and provided insights for marketing and outreach strategies to garner participation. Peak coincident demand reduction from 11 direct install lighting projects resulted in verified savings of ~39 kW pc , exceeding the 27 kW pc target - Throughout 2022, the implementation team launched several EWR pilots including Residential Appliance Recycling, C&I Prescriptive, Small Business, Lighting, HVAC and Food Service. - The Pilots include incentives to deliver off peak-load relief for premises connected to Fisher circuits. Early peak-load reduction estimates for year-end 2022 are reported at a 100 peak-kW reduction. These EWR pilot results exceed 2022 original forecast estimates by over double.

b. Pilot goals and desired learnings are detailed	• Determine the effectiveness of geo-targeted EWR and DR at addressing overloads at a substation • The NWA work at Fisher will provide a portion of the circuit load relief needed and allows for a lower cost traditional solution to provide the remaining needed load relief • The lessons learned will help develop future pilots and standardized processes that have the potential to reduce costs and potentially carbon emissions • The team is leveraging EWR offerings to both Residential and C&I customers served by this substation. • New lessons learned include the following: • Utilizing supplemental targeted outreach for existing programs has resulted in substantial savings • Several commercial customers have communicated a strong desire to participate • Targeted implementation requires a lot of communication • Existing programs with additional marketing and outreach, show higher levels of customer engagement
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021

(2) Pilot design and evaluation plan designed and presented together

a. Pilot design and evaluation plan designed and presented together	Pilot design and evaluation were presented in MPSC Case No. U-20147 filed on September 30, 2021 Measures include the following: • Verifying the load relief achieved from demand response • Determining if the targeted participation rates can be achieved • Understanding the time to deployment and the level of incentives needed to achieve the desired participation rates • Understanding customer acceptance of more frequent demand response interruptions • Verifying deployment costs and progress toward optimizing targeted marketing and administrative costs

b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	• Customer population: 4,425 Residential customers, 422 C&I customers • Selected substation based on peak load data at 116% of firm, and potential for Energy Efficiency and DR load relief of 56%, plus a STDF (Sub-transmission Distribution Facility) solution • Recruitment plans are to target market one Residential EE program and six C&I EE programs to select customers on the substation via geo-targeted program outreach and marketing
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	See (2) d. below
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	Specific statistical analyses will not be conducted, but DTE will be collecting and tracking a variety of metrics to measure: • Demand impact to expectation • Participation rate • Deployment time and incentives relationship to participation rates • Customer acceptance of more frequent demand response interruptions • Deployment costs

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	DR Scope and Cost • Marketing & Incentives (CoolCurrents & Smart Savers) • CoolCurrents equipment upgrades • Costs are included Exhibit A-12 Schedule B5.9 supported by witness Bennet and in Exhibit A-12, Schedule B5.6 supported by witness Farrell EWR Scope and Cost • Residential Implementation, incentive, and labor • C&I Implementation and Incentive • \$1.8M – 2021 to 2024 • EWR cost is supported by witness J.C.LeBrun in the MPSC Case U-20876 Exhibit A-11 and Exhibit A-14

	STDF Scope and Cost • Scope: Establish STDF (Subtransmission Distribution Facility) along same subtransmission line that feeds Fisher Substation. Split FISHR DC 8188 with STDF circuit. Install new conduit and cable • Cost ○ 2022: \$66,000 ○ 2023: \$180,000 - 2023 is design and construction for the reconductoring and design for the substation ○ 2024: \$4,524,000 - 2024 scope is substation construction (conduit, cable, 40kV overhead switch), load transfers & updating sectionalizing
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	No non-utility funding available
c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA technologies solutions deployed in these pilots will be used to evaluate economic and cost benefits.
d. Proposed rate recovery approach detailed	The STDF capital investment proposed for recovery in current case. EWR and DR programs to claim savings for measures installed from leveraging existing programs for NWA. Incremental EWR and DR expenses and load reductions will be attributed to the NWA pilot effort.

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	STDF Schedule • 2021 - Conceptual Engineering-complete • 2022 - Property Search-complete • 2023 - Detail Design and Construction • 2024 - Construction and In-commissioning EWR Programs Schedule • 2021 ○ Residential programs, September launch ○ C&I programs, September ramp up and launch • 2022-2024 ○ EWR programs continue through September 2024 ○ DR Schedule • 2021 ○ Establish program baseline-complete ○ Marketing-complete

	○ Introduce programs ○ Equipment upgrades 2022 – 2024 • Marketing ○ New customer acquisition ○ Existing customer education • CoolCurrents customer equipment upgrades

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	• DTE has worked with local businesses to discuss the scope of pilot offerings and benefits from participating • In 2022 EWR/DR marketing and communication plan included: ○ Outbound calls ○ Emails ○ Onsite assessments ○ Distributor outreach ○ Print collateral ○ Direct mail • Partner with NRDC for pilot review • Partner with Staff for pilot review
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	Effectiveness of EWR and DR to provide load relief on a geographically targeted basis

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	• Supports the transition to clean distributed resources utilizing EWR and DR programs to support demand reduction • Supports reliability through peak load relief • Supports customer affordability by lowering energy usage

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, shared.	New technologies such as energy waste reduction and demand response are becoming available for utilities to use to solve traditional electrical system loading issues. The NWA work at Fisher will provide a portion of the load relief needed and allows for a lower cost solution compared to traditional substation upgrades.
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Provide customer economic benefit by deploying new technologies that are lower in cost than traditional methods and can be deployed more rapidly
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service and equipment providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	See (6) c. above
f. Any other public benefits detailed.	Utilize EWR and DR as NWA solution reduces carbon emission

DTE Pilot Informational Document

Project Name: NWA: Battery Trailer
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	- Port Austin substation is 120% of firm rating¹ - Over firm for approximately 60 hours per year - One circuit is 108% of day-to-day²
b. Pilot goals and desired learnings are detailed	Pilot Goals: - Alleviate the substation overload and day-to-day circuit overloads 90% reduction in over firm duration by deploying solar and storage technology - Resolve low voltage conditions for customers at the end of circuit - Microgrid future development and deployment, operations, and validating reliability and economic benefits Lessons learned: - Evaluating the effectiveness and cost of using solar and storage as a technology to reduce risk of customer outages or power quality issue - Incorporate control, protection, and security requirements for storage - Develop new processes, procedures, and resources allocation

¹ Firm Rating: Ratings developed for each station and substation that outlines the allowable and safe thermal load which the entire facility and its associated equipment may serve

² Day-to-day: Allowable load a unit may carry on a day-to-day basis with the normal method of cooling applied to the transformer and regulator

c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	Measures will include the following: • Customer real time load demand impact compared to • Estimation • Deployment time • Deployment costs
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	N/A
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	See (2) a. above
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	See (2) a. above

(3) Pilot project costs detailed				
a. Project costs are detailed by source and amount for all applicable periods		2022	2023	2024
	Contract Labor	\$417,270	\$1,216,227	\$120,000
	DTE Labor	\$6,393	\$567,054	\$66,463
	Material	\$58,172	\$889,259	\$625,512
	Design			
	Engineering	\$38,000		
	Overheads	\$137,147	\$955,000	\$674,478
	Total	\$619,335	\$3,627,540	\$1,486,453
	Below are the highest cost items for the categories mentioned above: <u>Contract Labor</u>³: \$243K - Design services for underground and conduit installation \$227K – Underground construction service from vendor \$102K – Tree Trim \$206K – Miscellaneous <u>DTE Labor</u>: \$148K- DTE engineering \$24K- Substation operators \$50K – Contingency (SCADA and communications support) <u>Material</u>: \$295K – Overhead reconductoring including poles, conductors, and pole equipment \$246K – Solar Panels \$296K – Fiber for communication \$153K – Conduit and cable \$68K – Relay panels at substation site \$156K – Miscellaneous			
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	No non-utility funding available			
c. Projected cost-effectiveness of piloted measure at scale over expected life described	Cost effectiveness: The NWA solution is a pilot to assess if this technology can be deployed more rapidly and with similar costs compared to traditional solutions such as substation upgrades and circuits conversions. In addition to complying with the robust suite of NWAs expectation			

³ Contract labor services are bid out on competitive RFPs on a regular basis. These contracts contain fixed labor and equipment rates, and unit pricing for the duration of the contract. At the end of the contract term, DTE enters another RFP event to test the market competitiveness

	from the August 2020 Order, leveraging the customers solar and storage in a coordination with utility equipment deferred approximately \$10 million of system upgrades. The Company plans to reuse battery storage equipment from Omega after that project is completed, to reduce equipment purchase costs. The Company will use the standards developed from the Omega installation to increase the efficiency of design and construction. The Company will also use the assets deployed with some additional sectionalizing to further expand the NWA lessons learned. Expected Benefits The pilot will address the substation overload and result in 90% reduction in over firm hours which will improve customer reliability.
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• 2021 – 2022 ○ Property search - Complete ○ Conceptual engineering – Complete • 2022 ○ Start detail design - Complete ○ Purchase property - Complete • 2023 - 2024 ○ Detail design – In progress ○ Start construction – January 2023 ○ Complete battery installation – June 2024 ○ Complete solar installation – June 2024 ○ Evaluation of solar/storage to relieve loading conditions – June 2024 Schedule delays due to long lead time material causing delays to construction start. This project requires custom material (non DTE stock codes)

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	Partner with Staff for pilot review. DTE team will engage with local community leaders and officials

b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	N/A

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	New technologies such as batteries, solar panels and microgrids are becoming available for utilities to use to solve traditional electrical system concerns. Using these new technologies and integrating them with power generation strategies are opportunities to defer traditional investment.
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, shared.	N/A
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Provide customer economic benefit by deploying new technologies that are lower in cost than traditional methods and can be deployed more rapidly.
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service and equipment providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	See (6) c. above
f. Any other public benefits detailed.	N/A

DTE Pilot Informational Document

Project Name: NWA: Veridian
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• Net-zero community being developed with solar, storage and EV charging • Includes 50 low-income rental units developed by Avalon and 109 market rate housing units developed by Thrive • Base load + EV load could approach 1.5MVA • Fed by two circuits from Regent substation at 4.8kV, 81% firm rating, additional demand could overload circuit
b. Pilot goals and desired learnings are detailed	Pilot Goals: • Provide capacity to the circuit to accommodate incoming load with customer owned solar and storage • Microgrid development, engineering, operations, stability, and benefits • Effectiveness of solar and storage at reducing substation load • Understanding load criticality designation and testing load shedding sequence during islanded operation • Operating processes, procedures, and staffing Lessons learned: • This development combined with electrification will increase demand that require alternative designs to the underground cables and services compared to a standard residential tract development • Methods to manage a dynamic system consisting of many interacting customer owned DER and utility resources in normal operation and in a microgrid configuration.
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	• Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021 • Staff final report on New Technology and Business Model, MPSC Case No. U-20898, December 1, 2021

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	• By leveraging the onsite solar and storage capabilities as offsets to peak load, the proposed scope at Veridian is to reconductor existing circuit backbones and continue service from Regent substation • The NWA portion of the project will involve the use of microgrid controls; that manage the overall loading of the site through control of the solar, customer-owned storage, and potentially EV charging • Additional pilot designs and plans will be further developed upon receiving customer service application
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	The customers are the homeowners that will be residing in the Thrive Collaborative Community as part of the Veridian development in Ann Arbor.
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	Statistical analysis will not be conducted
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	• Area Load Analysis will continue to be conducted yearly to evaluate load relief conditions. AMI data will be leveraged to monitor customer voltage. • Funding for the project will come from a mix of DTE Electric, developer plus additional private and public funding

(3) Pilot project costs detailed					
a. Project costs are detailed by source and amount for all applicable periods		2022	2023	2024	2025
	Total	\$360,000	\$1,832,000	\$2,646,000	\$4,287,000
	Below are the highest cost items for the categories mentioned above: <u>Contract Labor</u> ¹ : \$800K – Storage installation \$180K – Interconnection studies \$160K – Design services \$55K – Tree trim <u>DTE Labor</u> : \$30K – Underground labor \$32K – Techs labor (operators, Pert techs etc.) <u>Material</u> ² : \$345K – Interconnection controls \$1,200K – Storage Unit				
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	Non-utility funding unavailable. DOE Connected Community grant application was denied				
c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA solution is a pilot to assess if this technology is cost effective compared to traditional substation upgrades that would be required to support this development				
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case				

¹ Contract labor services are bid out on competitive RFPs on a regular basis. These contracts contain fixed labor and equipment rates, and unit pricing for the duration of the contract. At the end of the contract term, DTE enters another RFP event to test the market competitiveness

² Major material is sourced on a competitive 3–5-year cycles, and where possible raw material is indexed per the COMEX indices to mitigate risk cost from suppliers. Overhead line material is typically bid annually per DTE's third party material integrator distribution operation

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• 2022: Engineering & Design-Completed • 2023-2026 ○ Overhead circuit construction ○ URD construction ○ Start of Microgrid implementation ○ Expand Microgrid as customer units are constructed

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	• Refine scope and expectations from the developer • Partner with MPSC Staff for pilot review
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	TBD

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	• Partner with the Ann Arbor community for pilot engagement • Stakeholder desires to explore a microgrid design for higher reliability and resiliency • Strong support from developers (both Thrive and Avalon) on the utility pilot • Strong support from city of Ann Arbor and Washtenaw County
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, shared.	New technologies (storage, demand response, solar panels, EV charging, etc.) are becoming available for utilities to use to solve traditional electrical system issues. Using these new technologies and integrating them with power generation strategies are opportunities to defer traditional investments.

c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Provide customer economic benefit by deploying new technologies that are lower in cost than traditional methods and can be deployed more rapidly
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service and equipment providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	• Provide customer economic benefit by deploying new technologies that are lower in cost than traditional methods and can be deployed more rapidly • Even though a small percentage of would install rooftop solar and other cutting-edge behind-the-meter technology, provide reliable power to low-income housing units
f. Any other public benefits detailed.	N/A

DTE Pilot Informational Document

Project Name: NWA: EV Charging Demonstration at ACM
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• Support the integration of electric vehicles including light duty and heavy duty • Establish the capabilities of utilizing charge management in concentrated scenarios and extreme fast charging environments • Evaluate the opportunity of vehicle to grid (V2G) including cyber security evaluation
b. Pilot goals and desired learnings are detailed	• Install a utility gateway and communications portal to enable charge management • Develop control algorithm and conduct testing on a extreme fast charger and its interfaces • Develop cyber security interfaces and control, install additional sensing capabilities, and monitor performance on a charging network • Develop monitoring and control algorithm for in-road inductive charging • Develop vehicle to grid capability utilizing standards such as SAE J3072 and IEEE1547
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Distribution Grid Plan, MPSC Case No. U-20147 filed on September 30, 2021

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	- Pilot design is part of the technical demonstration with the Department of Energy on vehicle electrification - Measures will include the following: - Cyber security prevention and protection - Development of a reference model of the cyber secure electric vehicle charge management architecture - Deployment of full capability to a large-scale site - Basic demonstration of capability in the field at a site - Demonstration of seamless grid integration - Interoperable monitoring and telemetry
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Not applicable
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	See (2) d. below
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	DTE will be collecting and tracking a variety of metrics including: - Development of a reference model of the cyber secure electric vehicle charge management architecture - Deployment of architecture to track the system performance of managing electric vehicle charging - Cyber security and interoperable standard adherence

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	- Engineering and Design - \$2.7M - Construction and Equipment – \$2.7M

b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	No non-utility funding available
c. Projected cost-effectiveness of piloted measure at scale over expected life described	Long term technology deployment will reduce the infrastructure investment needed for electric vehicle charging
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• 2021 – Conceptual Engineering and Design-Complete • 2022 – Engineering and initial construction -Complete • 2023 – Construction and start demonstration trials

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	• Partner with Staff for pilot review • Report reference model and learnings to the Department of Energy • Partner with Oakridge and Idaho national labs for demonstration of technology
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings
c. Expected publicly available data from pilot shared	At the end of the project, there will be a performance report of the project summarizing results and deliver to the Department of Energy

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	• Supports the transition to clean distributed resources utilizing EWR and DR programs to support demand reduction • Enhancing reliability, safety, affordability through demonstrating implementations of advanced distributed energy resources

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, shared.	New technologies (batteries, energy waste reduction, demand response, solar panels, etc.) are becoming available for utilities to use to solve traditional electrical system concerns and integrating them with future power generation strategies
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Facilitate electric vehicle infrastructure into the grid and reduce the amount of new infrastructure needed to support transportation electrification
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service providers and equipment wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	Enable solutions to allow easier integration of electric vehicle charging at multi-unit dwellings
f. Any other public benefits detailed.	N/A

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - 4.8kV Hardening &
Pole and Pole Top Maintenance and Modernization (PTMM) Details
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.4.8
Witnesses: M. Elliott Andahazy
T. M. Uzenski
Page: 1 of 1

(a)		(b)	(c)	(d)	(e)
Referenced Exhibit A-12 B5.4, page 8, lines 12 and 13					
Line No.	Description	Historical	Projected Calendar Year		
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025
1	4.8 kV Hardening - Line 12				
2	Inspection and Testing Costs	1,885	1,046	2,135	1,095
3	Overhead Construction	119,371	112,823	56,923	107,275
4	Line Clearance	36,226	14,188	23,077	17,725
5	Total 4.8 kV Hardening Details	157,482	128,056	82,135	126,095
6	Reclassify Inspections to O&M (effective 1/1/2023)	-	(1,046)	(2,135)	(1,095)
7	Total 4.8 kV Hardening after Reclassification	157,482	127,010	80,000	125,000
8	Pole and Pole Top Maintenance and Modernization - Line 13				
9	Inspection and Testing Costs	3,055	264	2,865	3,905
10	Reinforcements	623	148	317	602
11	Lines Miles Modernized	60,838	46,077	43,581	82,994
12	Pole Replacements	19,418	32,850	19,552	37,404
13	Total PTMM Details	83,934	79,339	66,315	124,905
14	Reclassify Inspections to O&M (effective 1/1/2023)	-	(264)	(2,865)	(3,905)
15	Total PTMM after Reclassification	83,934	79,075	63,450	121,000

1/ Projection adjustment carried to Exhibit A-13, Schedule C5.6

DTE Pilot Informational Document

Project Name: Adaptive Networked Microgrid (ANM)
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• Customer reliance on the electric system will continue to grow with additional electrification, driving the expansion of clean energy alternatives • DTEE is executing a series of all renewable, Non-Wires Alternative (NWA) projects that will expand future DER use and the learnings will be used to implement the ANM technology • The MPSC has communicated its desire for Michigan utilities to pursue IIJA Federal funding grants to support providing affordable, reliable, and equitable power to the State's citizens
b. Pilot goals and desired learnings are detailed	• Develop, test, and refine the concept of ANMs with two real-world deployments, in a rural and urban area. • Partner with the research and development community to both share lessons learned and gain insights from that community • Build industry's confidence in the new ANM technology to increase implementation on the system
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Selection of Application for Negotiation Under Funding Opportunity Announcement Number DE-FOA-0002740, BIL – Grid Resilience and Innovation Partnerships (GRIP), Topic Area 2

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	Measures will include the following: • Leveraging DER for greater customer reliability • Position Michigan with technical expertise in developing the future electrical system • Progress technology outside the NWA and microgrid space Seven areas of focus for Development and Testing: • <u>Project and Technical Management</u> – The Company will focus on good project management practices to manage the scope within budget and schedule. A major aspect of the technical management plan will be to develop good specifications early and refine them based on what is learned as the project progresses. • <u>Sensors and Data Analytics</u> – The greater flexibility offered by ANMs will require greater visibility into the electrical system. This will include deploying and using sensors with advanced machine learning applications such as fault locating, forecasting, and state estimation. • <u>Cybersecurity</u> – ANMs will include deploying more grid-edge devices, increasing the attack surface for cybersecurity concerns. The Company has a plan to continuously identify threats, simulate countermeasures, and deploy those countermeasures. • <u>Control and Protection</u> – Advanced controls is a critical area to tie the microgrids together to make the sectionalizing, forecasting, equipment, and other aspects work together. The dynamic boundaries of ANM will also require protection to evolve from a single setting to situationally aware or adaptive settings. • <u>Engineering Due Diligence</u> – Prior to field deployments, the Company will complete several steps to ensure the safe and proper operation of the new technology. This will occur through simulations and testing at the Company's Solar and Storage Lab in Westland, Michigan. • <u>Microgrid Deployment</u> – This area of focus takes the projects through the Company's gate process of engineer, design, construct, and closeout. • <u>Sharing Lessons Learned</u> – The Company will leverage lessons learned in the industry to make the project progress as efficiently as possible. In the spirit of collaboration, the Company will also share what it is learning during the project.

b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Develop and deploy pilot technology to benefit customer population in includes rural and urban areas.
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 benefits and functional performance will be monitored at the two pilot locations and projected for potential future deployments. These benefits will be compared to the costs of the project and projected cost of potential future deployments.
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	Specific statistical analyses will not be conducted, but DTE will be collecting and tracking a variety of metrics to measure: • Demand impact compared to expectation • Deployment time • Deployment costs • Reliability impact compared to expectation

(3) Pilot project costs detailed					
a. Project costs are detailed by source and amount for all applicable periods		2024	2025	2026	2027
	DTEE	\$1,976,607	\$12,437,241	\$6,047,973	\$1,359,926
	Partners	\$317,697	\$338,633	\$337,786	\$125,183
	DOE	\$2,294,003	\$12,774,310	\$6,385,303	\$1,484,878
	Total	\$4,588,307	\$25,550,184	\$12,771,062	\$2,969,987
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	50% cost sharing with DOE as a part of the grant – IJJA refer to above				
c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA solution is a pilot to assess if this technology is cost effective compared to our traditional restoration methods.				
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case				

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• Engineering Phase – 2024 ○ Specifications will be developed for the individual components and overall system. ○ Software (CYME and PSCAD) simulations will be completed. ○ The engineering needed for the Port Austin and O’Shea deployments will be finalized. ○ Achieving regulatory support is a gate to move forward past this phase. • Development Phase – 2025 ○ With regulatory and DOE support in place, the project will ramp-up significantly in phase 2. ○ Material will be ordered, design will be completed, and construction will start. ○ The specifications developed in phase 1 will be implemented by the team in phase 2. ○ Grid-edge and ADMS software will be developed, tested, and refined. ○ Hardware-in-the-loop testing will be completed. ○ Westland Equipment Yard testing will start. ○ Initial drafts of standards will be developed. ○ Initial testing, operating and maintenance procedures will be completed. • Deployment Phase – 2026 ○ After the successful completion of development work and engineering due diligence in phases 1 and 2, ANMs will be deployed in the field on two distribution circuits. • Assessment Phase – 2027 ○ With ANM deployments completed at Port Austin and O’Shea, the team will focus on monitoring the performance and benefits of the new technology.

(5) Stakeholder engagement plan detailed																	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	Partner with Staff for pilot review. Below is a table that describes the roles of the stakeholder partner organizations: <table> <tr> <th>Organization</th><th>Role</th></tr> <tr> <td>DTE Electric</td><td>Perform end-to-end project management. Complete engineering due diligence and testing. Implement engineering, design, and construction</td></tr> <tr> <td>Open Systems International (OSI)</td><td>OSI is the Company's ADMS supplier. The ADMS will be a key aspect of this advanced technology, and OSI will develop the centralized aspects of the control and forecasting needs.</td></tr> <tr> <td>Open Energy Solutions (OES)</td><td>Integrate advanced microgrid logic for grid-edge devices into an interoperable communication and control network between microgrid equipment.</td></tr> <tr> <td>Electric Power Research Institute (EPRI)</td><td>Viability analysis for networked microgrids, laboratory test plan development for networked microgrid controls and protection systems, flexible protection design and implementation for networked microgrids and factory and site acceptance test planning for networked microgrid controls and grid-forming inverters.</td></tr> <tr> <td>University of Michigan - Dearborn</td><td>Support the development and testing of cybersecurity practices. Also, develop a series of workshops in which industrial and national lab members, faculty, and students can share technical skills, internship opportunities, and other follow-on collaboration opportunities.</td></tr> <tr> <td>Lawrence Livermore National Laboratory (LLNL)</td><td>An advisor to the project on the development of black start technology, integration and optimal algorithms, de-energized line testing for public safety. Design and deployment of basic microgrids</td></tr> <tr> <td>National Renewable Energy Laboratory (NREL)</td><td>An advisor to the project on the development of distribution systems state estimation and microgrid control and monitoring.</td></tr> </table>	Organization	Role	DTE Electric	Perform end-to-end project management. Complete engineering due diligence and testing. Implement engineering, design, and construction	Open Systems International (OSI)	OSI is the Company's ADMS supplier. The ADMS will be a key aspect of this advanced technology, and OSI will develop the centralized aspects of the control and forecasting needs.	Open Energy Solutions (OES)	Integrate advanced microgrid logic for grid-edge devices into an interoperable communication and control network between microgrid equipment.	Electric Power Research Institute (EPRI)	Viability analysis for networked microgrids, laboratory test plan development for networked microgrid controls and protection systems, flexible protection design and implementation for networked microgrids and factory and site acceptance test planning for networked microgrid controls and grid-forming inverters.	University of Michigan - Dearborn	Support the development and testing of cybersecurity practices. Also, develop a series of workshops in which industrial and national lab members, faculty, and students can share technical skills, internship opportunities, and other follow-on collaboration opportunities.	Lawrence Livermore National Laboratory (LLNL)	An advisor to the project on the development of black start technology, integration and optimal algorithms, de-energized line testing for public safety. Design and deployment of basic microgrids	National Renewable Energy Laboratory (NREL)	An advisor to the project on the development of distribution systems state estimation and microgrid control and monitoring.
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DTE Electric	Perform end-to-end project management. Complete engineering due diligence and testing. Implement engineering, design, and construction																
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Electric Power Research Institute (EPRI)	Viability analysis for networked microgrids, laboratory test plan development for networked microgrid controls and protection systems, flexible protection design and implementation for networked microgrids and factory and site acceptance test planning for networked microgrid controls and grid-forming inverters.																
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National Renewable Energy Laboratory (NREL)	An advisor to the project on the development of distribution systems state estimation and microgrid control and monitoring.																
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings																
c. Expected publicly available data from pilot shared	Lessons learned from the project will be shared in technical papers, annual information sessions with the technical community, periodic discussions with the MPSC Staff, and through other channels. Critical Electrical Infrastructure Information (CEII), customer information will not be shared.																

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	- Utilize the DER technology to integrate distributed energy resources for a smarter grid - Reduce emissions compared to the use of traditional portable diesel generators

	Implemented advanced technology solutions faster and for lesser costs than the traditional solutions for customer reliability
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, shared.	New technologies such as batteries are becoming available for utilities to use to solve traditional electrical system concerns. Using these solutions for advanced microgrids will provide additional reliability and customer benefits
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Utilize DERs for system resiliency and reliability
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	Reduce emissions compared to the use of traditional portable diesel generators in communities of vulnerable populations. Additionally, one of the two planned areas for construction of the microgrid (the O'Shea Solar Park project) is located directly within an environmental justice community (EJ). This will benefit the EJ area and support the neighboring areas as well.
f. Any other public benefits detailed.	N/A

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Community Lighting
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.5
Witness: R. Bellini
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period		Projected Test Year		In Service
Line		12 mos. ended	12 mos. ending	12 mos. ending	24 mos. ending	12 mos. ending	Year
No.	Description	12/31/2022	12/31/2023	12/31/2024	12/31/2024	12/31/2025	
					<i>col. (c)+(d)</i>		
1	New Installations and Replacements	6,301	5,495	6,300	11,795	6,300	Annual
2	Outage Restoration	7,349	9,144	6,900	16,044	6,900	Annual
3	Post Replacement	1,540	684	1,800	2,484	1,800	Annual
4	Cable Replacement	1,687	1,490	1,125	2,615	1,725	Annual
5	HID Conversions	<u>942</u>	<u>(113)</u>	<u>575</u>	<u>462</u>	<u>575</u>	Annual
6	Total Community Lighting	<u>17,820</u>	<u>16,700</u>	<u>16,700</u>	<u>33,400</u>	<u>17,300</u>	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Demand Response Portfolio and DTE Insight
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.6
Witnesses: K. O. Farrell
Page: 1 of 2

(a)		(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	Capital Expenditures				Projected Test Year	In Service Year
		Historical	Projected Bridge Period				
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024		
		col. (c)+(d)					
1	Interruptible Space Conditioning (CoolCurrents)	1,073	1,718	500	2,218	500	Annual
2	Programmable Controllable Thermostats (SmartCurrents)	3,850	4,253	4,000	8,253	2,500	Annual
3	Other Demand Response Programs and Pilots (1)	3,034	4,029	2,900	6,929	1,400	Annual
4	Subtotal Demand Response Portfolio	7,957	10,000	7,400	17,400	4,400	
5	DTE Insight	1,443	675	675	1,350	1,600	Annual
6	Total	9,400	10,675	8,075	18,750	6,000	

(1) Includes \$1,990 of disallowed C&I battery costs from Case No. U-21297.

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Demand Response Portfolio
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.6
Witnesses: K. O. Farrell
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	Capital Expenditures				Projected Test Year
		Historical	Projected Bridge Period			
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	
					col. (c)+(d)	
1	CoolCurrents					
2	- Materials	(54)	727	115	842	208
3	- Contractor/Outside Services	880	790	240	1,030	224
4	- Labor & Overheads	248	200	145	345	68
5	Total	1,073	1,718	500	2,218	500
6	Smart Currents					
7	- Materials	504	60	1,598	1,658	781
8	- Contractor/Outside Services	3,156	3,952	2,197	6,149	1,501
9	- Labor & Overheads	190	241	205	446	218
10	Total	3,850	4,253	4,000	8,253	2,500
11	Other Demand Response Programs and Pilots					
12	- Materials	2,488	3,574	1,590	5,164	17
13	- Contractor/Outside Services	138	2	863	865	856
14	- Labor & Overheads	408	453	447	900	527
15	Total	3,034	4,029	2,900	6,929	1,400
16	DTE Insight					
17	- Materials	-	10	10	21	10
18	- Contractor	1,359	651	651	1,303	1,576
19	- Labor & Overheads	84	14	14	27	14
20	Total	1,443	675	675	1,350	1,600
21	Total Demand Response Portfolio	9,400	10,675	8,075	18,750	6,000

DTE Pilot Informational Document

Project Name: DR C&I Battery Storage Pilot
Included with Case: Case No. U-21534
Sponsoring Witness: Keegan O. Farrell

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	The C&I Battery Storage pilot is designed to test the ability to achieve peak demand shaving or shifting during DR events. The Company will look to partner with two C&I customers for a two-year pilot period following installation and commissioning of the batteries. Both battery systems are intended to be operational by the end of 2025.
b. Pilot goals and desired learnings are detailed	The main objectives of the pilot are as follows: • Engage with customers to better understand their interest in hosting and potentially operating a BESS; • Gain operational experience on battery installation, management, and control interfaces when the system is located at a customer's site as opposed to a Company site; • Assess feasibility for sharing asset control between customer and the Company; • Evaluate the effectiveness of the BESS to achieve system peak demand reduction when a demand response event is called by the Company; • Assess customer's actions to achieve demand charge and overall bill reductions; • Facilitate the understanding of multiple energy storage values, compensation models, and the integration of battery storage in wholesale markets to support tariff development as contemplated by the Commission's Order in MPSC Case No. U-21032.
Additional information is available in the testimony of Company Witness Farrell	Q62, Q63, Q64

(2) Pilot design and evaluation plan designed and presented together

a. Pilot design and evaluation plan designed and presented together	The battery will be up to 250 kW/1 MWh at two sites to reduce peak customer and system demand. A Request for Information (RFI) was issued to provide the Company with a better assessment of the equipment availability and flexibility. A Request for Proposal (RFP) was also issued, which lead to the final selection of a specific equipment provider and integrator, Hitachi. The Company will retain the ability to control the BESS when calling a dispatch event and the customer will retain the ability to control the BESS during non-event periods. The initial proposed DR event schedule includes no more than 30 planned DR events per year and five emergency DR events, with a least one-hour customer notice, per year.
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	The pilot will target customers who are enrolled on the Company's D4 rate, D6.2 rate, or D11 rate. As part of the implementation plan, the Company has identified one customer. The Company is confident that a second participant will be identified in partnership with Company's Major Account Services (MAS) group in the first half of 2024 and that the second battery will be installed shortly after the first.
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	TBD if such an analysis is applicable.
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	The pilot will target customers who are enrolled on the Company's D4 rate, D6.2 rate, or D11 rate. Customer selection will be evaluated on a case-by-case basis in order to technically assess the most appropriate site to best match the pilot specs.
Additional information is available in the testimony of Company Witness Farrell	Q63, Q64

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	The Company anticipates spending \$1.4 million during the bridge period and \$0.6 million in the forecasted test year. Capital spend was moved to 2024 and 2025 due to lead time of major equipment critical for progression of both batteries. Associated estimated capital costs are included in Other Demand Response Pilots funding shown in Exhibit A-12, Schedule B5.6.

b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	N/A
c. Projected cost-effectiveness of piloted measure at scale over expected life described	N/A
Additional information is available in the testimony of Company Witness Farrell	Q34, Q65, Q66, Q67,

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	Due to lead time of major equipment, installation at the first customer's site has taken longer than anticipated although is targeted for Q2 2025. Once the second customer has been identified and the first installation is underway, the installation of the second battery will begin. The Company plans for both batteries to be operational by the end of 2025.
Additional information is available in the testimony of Company Witness Farrell	Q64

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	DTE Electric will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
b. Interim and final stakeholder reporting described	DTE Electric will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
c. Expected publicly available data from pilot shared	N/A
Additional information is available in the testimony of Company Witness Farrell	N/A

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	TBD
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, shared.	The Company designs and executes DR pilots to help customers reduce their peak energy use, which provides value to the participating customers in the form of savings or other compensation, to the utility through reduced capacity needs and lower capacity costs and all customers through reduced overall system costs.
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	TBD
d. Expected local or Michigan based employment and business opportunities created by pilot described.	TBD
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	TBD
Additional information is available in the testimony of Company Witness Farrell.	N/A

DTE Pilot Informational Document

Project Name: DR Residential Generator Pilot
Included with Case: Case No. U-21534
Sponsoring Witness: Keegan O. Farrell

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	The generator pilot is targeted towards residential customer-owned natural gas generators. The pilot leverages a third-party service provider, Generac Grid Services', platform utilizing telemetry to shift the customer's electric load to the customer's generator in real-time during peak events. Pilot participants benefit by receiving incentives from the Company.
b. Pilot goals and desired learnings are detailed	The main objectives of the residential generator pilot are as follows: • Determine whether customers would be willing to actively participate and allow for real-time telemetry to control their generators during an event; • Assess the viability of a pilot that can act as a year-round DR asset responding on short-term notice for peak events; • Measure how effective the customer-owned generators respond as a year-round LMR; • Assess customer receptiveness and the value customers receive from a residential generator pilot; and • Identify and process new learnings that could be applied to current and future demand response offerings.
Additional information is available in the testimony of Company Witness Farrell	Q66, Q67

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	The generator pilot is designed to provide significant data: customer acquisition, customer engagement, customer retention, and load

	shed to evaluate the viability of utilizing customer-owned natural gas generators as a year-round LMR to provide load reduction.
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Phase 1 2023: enrolled 197 participants, with a 200-participant cap, via email recruitment efforts, who have a dealer managed or premium Mobile Link subscription. The dealer managed or premium Mobile Link subscription allows the Company to operate a switch-free program capable of remote operations such as responding to demand response events. Customers received an up-front gift card of \$100 and will receive a \$250 gift card for remaining enrolled at the end of the pilot term as well as reduced electric bills during peak events. Phase 2 2024: The Company is considering a second phase of recruitment to target up to 200 additional participants The Company will call demand response events during the pilot term and evaluate actual kWh reduction. In partnership with Generac, the Company will send customer satisfaction surveys annually, and potentially through out the year post demand response events.
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	TBD
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	The following metrics will be in place and tracked to measure pilot effectiveness: customer acquisition and enrollment rates (including attrition), marketing metrics (outreach activities and their impact), customer opt-out rate, and load shed during different type of events.
Additional information is available in the testimony of Company Witness Farrell	Q67, Q68, Q69

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	Associated estimated O&M costs are included in Witness Bennet's exhibit, A-13, Schedule C5.9.

b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	N/A
c. Projected cost-effectiveness of piloted measure at scale over expected life described	N/A
Additional information is available in the testimony of Company Witness Farrell	Q65 & Q68

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	The Company has selected Generac Grid Services through the Request for Information (RFI) process. Marketing efforts and customer enrollment began mid-July and resulted in 197 successful enrollments. Phase 2 of marketing and customer enrollment is tentatively planned for 2024. The pilot will conclude in December 2025.
Additional information is available in the testimony of Company Witness Farrell	Q69

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	DTE will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
b. Interim and final stakeholder reporting described	DTE will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
c. Expected publicly available data from pilot shared	N/A
Additional information is available in the testimony of Company Witness Farrell	N/A

(6) Public interest detailed

a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	TBD
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, shared.	The Company designs and executes DR pilots to help customers reduce their peak energy use, which provides value to the participating customers in the form of savings or other compensation, to the utility through reduced capacity needs and lower capacity costs and all customers through reduced overall system costs.
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	TBD
d. Expected local or Michigan based employment and business opportunities created by pilot described.	TBD
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	TBD
Additional information is available in the testimony of Company Witness Farrell.	N/A

DTE Pilot Informational Document

Project Name: DR Residential Vehicle to Home (V2H)
Included with Case: Case No. U-21534
Sponsoring Witness: Keegan O. Farrell

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	The V2H pilot is targeted towards residential electric or combination electric and gas customers who own an eligible Electric Vehicle (EV) through the Company's participating Original Equipment Manufacturers (OEMs), and has a bi-directional charging station already installed. The pilot will leverage each OEMs preferred platform, utilizing vehicle telemetry to shift the customer's electric load from charging to discharging during Demand Response (DR) events throughout the pilot year. Pilot participants will benefit by receiving incentives from the Company and by charging at a lower rate during off-peak times and discharging during on-peak times when the price is higher. This will be one of the first V2H pilots launched across the country.
b. Pilot goals and desired learnings are detailed	The main objectives of the V2H pilot are as follows: • Targeting and recruitment efforts needed to enroll in this type of pilot; • Determining the appropriate time and length to dispatch events based on the most optimal time to charge and discharge the EV for the participant and the Company; • Understanding what incentive structure prompts customer participation; • Determining how much demand (kW) and energy (kWh) savings the Company could expect to achieve with the pilot's current participants as well as future potential as additional eligible EV models are available in DTE Electric's service territory; • Assessing customer receptiveness and the value to the participants and the Company for this type of V2H pilot; and • Identifying and processing new learnings that could be applied to current and future DR V2H offerings
Additional information is available in the testimony of Company Witness Farrell	Q76, Q77

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	The V2H pilot is designed to provide data and learnings around customer acquisition, customer engagement, customer retention, and load shed to evaluate the viability of utilizing eligible EV models paired with the bi-directional charging station for this V2H concept as a DR resource. Evaluating how participants and EVs respond to the different event times, lengths and incentives offered will help guide us to a better program design in the future.
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	The Company plans to target up to 400 eligible participants with an EV from our OEM partners in its first pilot year to ensure that any issues (i.e., communication or signal issues) are resolved prior to an expansion to the Company's broader electric customers with eligible EV models. The OEMs will launch marketing campaigns through email and in-app push notifications to eligible participants. The V2H participants will receive up to \$500 in incentives for their enrollment and participation in events. The Company will call DR events during the pilot term and evaluate how much energy (kWh) and demand (kW) reduction should be expected from this type of pilot. In partnership with the OEMs, the Company will send customer satisfaction surveys near the end of the pilot year and post demand response events, as well as potentially throughout the year, to learn from customer experiences during called DR events.
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	TBD
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	The following metrics will be in place and tracked to measure pilot effectiveness: customer acquisition and enrollment rates (including attrition), marketing metrics (outreach activities and their impact), customer opt-out rate, and load shed during different type of events.
Additional information is available in the testimony of Company Witness Farrell	Q76, Q77

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	The incentive costs associated with customer enrollment and participation, \$0.1m, will be funded by Demand Response. The costs associated with the software components and monthly EV fees of the participating OEMs were funded by the Emerging Tech Fund, which is further described in MPSC Case No. U-20836 Burns Testimony, Q111.
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	N/A
c. Projected cost-effectiveness of piloted measure at scale over expected life described	N/A
Additional information is available in the testimony of Company Witness Farrell	Q70, Q76

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	The pilot launch date is targeted to begin by June 30, 2024. The main agreement between the Company and OEMs are still being finalized; the pilot is scheduled to run for 12 months after the completion of the Statement of Work (SOW).
Additional information is available in the testimony of Company Witness Farrell	Q76

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	DTE Electric will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
b. Interim and final stakeholder reporting described	DTE Electric will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
c. Expected publicly available data from pilot shared	N/A

Additional information is available in the testimony of Company Witness Farrell	N/A

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	TBD
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, shared.	The Company designs and executes DR pilots to help customers reduce their peak energy use, which provides value to the participating customers in the form of savings or other compensation, to the utility through reduced capacity needs and lower capacity costs and all customers through reduced overall system costs.
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	TBD
d. Expected local or Michigan based employment and business opportunities created by pilot described.	TBD
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	N/A
Additional information is available in the testimony of Company Witness Farrell.	N/A

DTE Pilot Informational Document

Project Name: Smart Charge (EV Managed Charging)
Included with Case: Case No. U-21534
Sponsoring Witness: Keegan O. Farrell

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	For the 2023-24 pilot year, the DTE rolled out a managed charging pilot with Smart Charge. DTE Smart Charge is designed to help EV drivers in DTE Electric service territory to manage their charging to occur during the most optimal times of day for grid operation. DTE coordinates directly with participating OEMs: Ford, GM, BMW, and Tesla to schedule daily charging to meet driver's needs while allowing for interruptions to EV charging during periods of the grid's peak energy usage. DTE Smart Charge is designed to schedule EV charging during off-peak time periods based on the customer's electric rate. The Company plans to call up to five DR events, June through September, to evaluate how much demand and energy can be achieved. To incentivize participation in this program, DTE Electric offers customers up to \$100 dollars in gift cards for joining and remaining on the program. This incentive is paid out as a \$50 up-front gift card at the time of enrollment and a \$50 gift card upon the conclusion of the program in December 2024.
b. Pilot goals and desired learnings are detailed	The main objectives of the Smart Charge pilot are as follows: • Determining the appropriate time and length to dispatch events based on the most optimal time for the participant and the Company to charge the EV; • Roll out automated charging based on day-ahead pricing to ensure the EV is charging at the lowest time during their off-peak rate schedule; • Understanding what incentive structure prompts customer participation; • Determining how much demand (kW) and energy (kWh) savings the Company could expect to achieve with the pilot's current participants as well as future potential as additional eligible EV models are available in DTE Electric's service territory;

	- Assessing customer receptiveness and the value to the participants and the Company for this type of managed charging pilot; and - Identifying and processing new learnings that could be applied to current and future DR managed charging offerings
Additional information is available in the testimony of Company Witness Farrell	Q71, Q72

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together	The Smart Charge pilot is designed to provide data and learnings around customer acquisition, customer engagement, customer retention, and load shed to evaluate the viability of utilizing eligible EV models for managed charging and DR curtailment events as a DR resource. Evaluating how participants and EVs respond to the different event times, lengths and incentives offered will help guide us to a better program design in the future.
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	The Company plans to target up to 2,000 DTE residential electric customers with an eligible EV model from Ford, GM, BMW and Tesla. The OEMs will launch marketing campaigns through email and in-app push notifications to eligible participants, while the Company will launch targeted email marketing campaigns. The participants will receive up to \$100 in incentives for their enrollment and participation in events. The Company will call DR events during the pilot term and evaluate how much energy (kWh) and demand (kW) reduction occurred during managed charging and DR events. In partnership with the OEMs, the Company will send customer satisfaction surveys near the end of the pilot year and post demand response events, as well as potentially throughout the year, to learn from customer experiences during called DR events.
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	TBD

d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	The following metrics will be in place and tracked to measure pilot effectiveness: customer acquisition and enrollment rates (including attrition), marketing metrics (outreach activities and their impact), customer opt-out rate, and load shed during different type of events.
Additional information is available in the testimony of Company Witness Farrell	Q71, Q72, Q73

(3) Pilot project costs detailed	
a. Project costs are detailed by source and amount for all applicable periods	The cost of Smart Charge is projected to be \$0.8m to support the expansion of the Smart Charge Program. The costs are associated with platform fees, marketing and customer participation incentives. The use of WeaveGrid in 2023 and the first five (5) months of 2024 was funded through the Emerging Tech Fund (ETF) as described in Q/A 111 of Witness Burns' Testimony case U-20836.
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	
c. Projected cost-effectiveness of piloted measure at scale over expected life described	
Additional information is available in the testimony of Company Witness Farrell	Q70, Q74

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	The pilot launched in July 2023 and will run through December 2024.
Additional information is available in the testimony of Company Witness Farrell	Q71, Q72

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed	DTE Electric will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and

	highlight pilot details in annual Demand Response Reconciliation filings.
b. Interim and final stakeholder reporting described	DTE Electric will regularly engage with Commission Staff during periodic check-in meetings and will also provide pilot updates and highlight pilot details in annual Demand Response Reconciliation filings.
c. Expected publicly available data from pilot shared	N/A
Additional information is available in the testimony of Company Witness Farrell	N/A

(6) Public interest detailed	
a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	The Company believes that the Smart Charge pilot should become part of the Company's DR portfolio beginning in 2025. With continued allocated O&M resources, along with the forecasted increased adoption of EVs, Smart Charge is expected to continue expanding. Transitioning Smart Charge to a program also allows for more customers to participate in the program above the current pilot customer cap of 2,000. In addition, with this commitment, the Company will remain at the forefront of developing technologies and continue to collaborate with important OEMs within the service territory as EV adoption continues to grow.
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, shared.	The Company designs and executes DR pilots to help customers reduce their peak energy use, which provides value to the participating customers in the form of savings or other compensation, to the utility through reduced capacity needs and lower capacity costs and all customers through reduced overall system costs.
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	TBD
d. Expected local or Michigan based employment and business opportunities created by pilot described.	TBD

e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	N/A
Additional information is available in the testimony of Company Witness Farrell.	Q73

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Information Technology
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7
Witness: P. Sharma, M. Hatsios
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Capital Expenditures						
		Historical	Projected Bridge Period			Projected Test Year	
Line No.	Description	12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025	Reference
					<i>col. (c)+(d)</i>		
1	IT Expenditures by Portfolio:						
2	Corporate Applications	17,087	4,518	13,218	17,736	12,375	Exhibit A-12 Sch B5.7.1
3	Customer Service (Sustainment and Return to Health)	21,604	30,479	21,010	51,489	18,529	Exhibit A-12 Sch B5.7.2
4	Customer Service (Strategic, Enhancements & Compliance)	62,082	45,487	29,095	74,582	33,024	Exhibit A-12 Sch B5.7.3 **
5	Plant & Field	58,910	20,261	27,425	47,686	22,648	Exhibit A-12 Sch B5.7.4
6	Information Technology for IT	5,153	2,491	16,622	19,113	2,111	Exhibit A-12 Sch B5.7.5
7	Information Protection Security	6,063	4,000	6,632	10,632	7,172	Exhibit A-12 Sch B5.7.6
8	Infrastructure Operations	45,087	51,074	36,718	87,792	48,264	Exhibit A-12 Sch B5.7.7
9	Enterprise Data Analytics	5,521	4,000	1,561	5,561	1,530	Exhibit A-12 Sch B5.7.8
10	Innovations	2,789	-	-	-	-	Exhibit A-12 Sch B5.7.9
11	Total	224,295	162,310	152,281	314,591	145,653	
** Customer Service (Strategic, Enhancements & Compliance) on Line 4 is sponsored by Witness Hatsios							
12	Total Expenditures by Major Category:						
13	Regulatory/Compliance	22,856	15,749	10,485	26,234	23,129	Exhibit A-12 Sch B5.7 page 2
14	Sustainment	28,222	60,870	55,151	116,022	56,236	Exhibit A-12 Sch B5.7 page 2
15	Return-to-Health	69,517	35,134	31,458	66,592	25,504	Exhibit A-12 Sch B5.7 page 2
16	IT Enhancements	17,891	7,657	2,569	10,226	8,137	Exhibit A-12 Sch B5.7 page 2
17	Strategic	83,093	42,196	52,223	94,419	31,745	Exhibit A-12 Sch B5.7 page 2
18	IT Projects<\$250K	2,715	704	395	1,099	902	Exhibit A-12 Sch B5.7 page 2
19	Total	224,295	162,310	152,281	314,591	145,653	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Information Technology
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Capital Expenditures					Projected Test	
Line	Historical	Projected Bridge Period			Year		
No.	Description	12 mos. ended	12 mos. ended	12 mos. ending	12 mos. ended	12 mos. ended	Reference
		12/31/2022	12/31/2023	12/31/2024	12/31/2024	12/31/2025	
					col. (c)+(d)		
1	Regulatory/Compliance						
2	Corporate Applications	1,138	1,437	1,668	3,105	1,800	Exhibit A-12 Sch B5.7.1
3	Customer Service	21,107	13,055	8,242	21,297	17,448	Exhibit A-12 Sch B5.7.3 (Hatsios)
4	Plant & Field	-	-	-	-	1,296	Exhibit A-12 Sch B5.7.4
5	Information Technology for IT	-	-	-	-	-	Exhibit A-12 Sch B5.7.5
7	Information Protection Security	-	977	425	1,402	2,305	Exhibit A-12 Sch B5.7.6
8	Infrastructure Operations	612	280	150	430	280	Exhibit A-12 Sch B5.7.7
9	Enterprise Data Analytics	-	-	-	-	-	Exhibit A-12 Sch B5.7.8
6	Innovations	-	-	-	-	-	Exhibit A-12 Sch B5.7.9
10	Total Regulatory/Compliance	22,856	15,749	10,485	26,234	23,129	
11							
12	Sustainment						
13	Corporate Applications	3,571	2,504	4,412	6,916	3,896	Exhibit A-12 Sch B5.7.1
14	Customer Service	6,881	14,091	14,020	28,111	16,229	Exhibit A-12 Sch B5.7.2
15	Plant & Field	15,909	8,195	10,873	19,068	9,000	Exhibit A-12 Sch B5.7.4
16	Information Technology for IT	1,669	1,391	16,622	18,013	1,695	Exhibit A-12 Sch B5.7.5
18	Information Protection Security	-	-	-	-	-	Exhibit A-12 Sch B5.7.6
19	Infrastructure Operations	193	34,688	7,663	42,351	23,886	Exhibit A-12 Sch B5.7.7
20	Enterprise Data Analytics	-	-	1,561	1,561	1,530	Exhibit A-12 Sch B5.7.8
17	Innovations	-	-	-	-	-	Exhibit A-12 Sch B5.7.9
21	Total Sustainment	28,222	60,870	55,151	116,022	56,236	
22							
23	Return-to-Health						
24	Corporate Applications	-	-	3,268	3,268	2,577	Exhibit A-12 Sch B5.7.1
25	Customer Service	14,080	16,285	6,990	23,275	2,300	Exhibit A-12 Sch B5.7.2
26	Plant & Field	27,803	6,914	6,235	13,149	6,614	Exhibit A-12 Sch B5.7.4
27	Information Technology for IT	-	-	-	-	-	Exhibit A-12 Sch B5.7.5
29	Information Protection Security	157	700	1,060	1,760	730	Exhibit A-12 Sch B5.7.6
30	Infrastructure Operations	27,477	11,234	13,905	25,139	13,283	Exhibit A-12 Sch B5.7.7
31	Enterprise Data Analytics	-	-	-	-	-	Exhibit A-12 Sch B5.7.8
28	Innovations	-	-	-	-	-	Exhibit A-12 Sch B5.7.9
32	Total Return-to-Health	69,517	35,134	31,458	66,592	25,504	
33							
34	IT Enhancements						
35	Corporate Applications	1,938	365	-	365	-	Exhibit A-12 Sch B5.7.1
36	Customer Service	7,422	2,166	2,000	4,166	7,171	Exhibit A-12 Sch B5.7.3 (Hatsios)
37	Plant & Field	-	-	-	-	-	Exhibit A-12 Sch B5.7.4
38	Information Technology for IT	254	113	-	113	-	Exhibit A-12 Sch B5.7.5
40	Information Protection Security	454	287	314	601	316	Exhibit A-12 Sch B5.7.6
41	Infrastructure Operations	2,302	727	255	982	650	Exhibit A-12 Sch B5.7.7
42	Enterprise Data Analytics	5,521	4,000	-	4,000	-	Exhibit A-12 Sch B5.7.8
39	Innovations	-	-	-	-	-	Exhibit A-12 Sch B5.7.9
43	Total IT Enhancements	17,891	7,657	2,569	10,226	8,137	
44							
45	Strategic						
46	Corporate Applications	10,158	-	3,535	3,535	4,102	Exhibit A-12 Sch B5.7.1
47	Customer Service	33,210	30,183	18,853	49,036	8,405	Exhibit A-12 Sch B5.7.3 (Hatsios)
48	Plant & Field	14,725	4,860	10,257	15,117	5,500	Exhibit A-12 Sch B5.7.4
49	Information Technology for IT	2,523	986	-	986	-	Exhibit A-12 Sch B5.7.5
51	Information Protection Security	5,195	2,022	4,833	6,855	3,573	Exhibit A-12 Sch B5.7.6
52	Infrastructure Operations	14,491	4,146	14,745	18,891	10,165	Exhibit A-12 Sch B5.7.7
53	Enterprise Data Analytics	-	-	-	-	-	Exhibit A-12 Sch B5.7.8
50	Innovations	2,789	-	-	-	-	Exhibit A-12 Sch B5.7.9
54	Total Strategic	83,093	42,196	52,223	94,419	31,745	
55							
56	IT Projects<\$250K						
57	Corporate Applications	283	212	335	547	-	Exhibit A-12 Sch B5.7.1
58	Customer Service	986	186	-	186	-	Exhibit A-12 Sch B5.7.2
59	Plant & Field	473	291	60	351	238	Exhibit A-12 Sch B5.7.4
60	Information Technology for IT	706	1	-	1	416	Exhibit A-12 Sch B5.7.5
62	Information Protection Security	256	14	-	14	248	Exhibit A-12 Sch B5.7.6
63	Infrastructure Operations	12	-	-	-	-	Exhibit A-12 Sch B5.7.7
64	Enterprise Data Analytics	-	-	-	-	-	Exhibit A-12 Sch B5.7.8
61	Innovations	-	-	-	-	-	Exhibit A-12 Sch B5.7.9
65	Total IT Projects<\$250K	2,715	704	395	1,099	902	
66							
67	Total Information Technology	224,295	162,310	152,281	314,591	145,653	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Information Technology
(\$000)

Case No.: U-21534
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Capital Expenditures									
Line No.	Description	Actual	Projected Calendar Year			Projected Bridge Period		Projected Test Year	Reference
		12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ended 12/31/2024	12 mos. ended 12/31/2025	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	12 mos. ended 12/31/2025	
1	Shared Asset Expenditures								
2	Corporate Applications	17,087	4,518	11,401	12,375	4,518	11,401	12,375	Exh. A-12 B5.7.1, Line 25
3	Plant & Field	7,237	6,889	5,467	8,821	6,889	5,467	8,821	Exh. A-12 B5.7.4, Line 42
4	Information Technology for IT	5,153	2,491	16,622	2,111	2,491	16,622	2,111	Exh. A-12 B5.7.5, Line 10
5	Information Protection Security	6,063	4,000	6,632	7,172	4,000	6,632	7,172	Exh. A-12 B5.7.6, Line 22
6	Infrastructure Operations	36,190	46,190	22,515	38,061	46,190	22,515	38,061	Exh. A-12 B5.7.7, Line 52
7	Enterprise Data Analytics	5,521	4,000	1,561	1,530	4,000	1,561	1,530	Exh. A-12 B5.7.8, Line 7
8	Innovations	2,789	-	-	-	-	-	-	Exh. A-12 B5.7.9, Line 6
9	Subtotal Corporate Support IT	80,039	68,088	64,198	70,070	68,088	64,198	70,070	
10	Customer Service (Sustainment and Return to Health)	15,252	24,774	18,020	15,394	24,774	18,020	15,394	Exh. A-12 B5.7.2, Line 29
11	Customer Service (Strategic, Enhancements & Compliance)	28,398	20,995	16,540	18,519	20,995	16,540	18,519	Exh. A-12 B5.7.3, Line 52
12	Subtotal Customer Service IT	43,650	45,769	34,560	33,913	45,769	34,560	33,913	
13	Total	123,690	113,857	98,758	103,983	113,857	98,758	103,983	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Information Technology
(\$000)

Case No.: U-21534
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(a)		(b)	(c)
Line No.	Description	Adjusted Historical 12 mos. ended 12/31/2022	Projected 12 mos. ended 12/31/2025
1	AFUDC - Information Technology	4,902	3,268

Notes:

AFUDC estimates are developed at a high level based on historical trend

The projected AFUDC amounts are based on the authorized U-21297 of 5.561%

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures
Corporate Applications Projects (\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7.1
Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Category	Shared/ Electric Only	Historical 12 mos. ended 12/31/2022	Projected Bridge Period			Projected Test Period	Business Case Reference	In Service Year
					12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025		
1	Core ERP Stacks and Packs	Regulatory/Compliance	Shared	1,138	1,437	1,668	3,105	1,800	BCD-CA-22-006, DMND0001215	Annual
2	Corporate Services Application Health	Sustainment	Shared	481	507	779	1,286	775	BCD-CA-22-011, DMND0001218	Annual
3	Documentum (EDM) Application Health	Sustainment	Shared	-	110	392	502	387	DMND0001382	Annual
4	Enterprise Applications Health	Sustainment	Shared	385	366	740	1,106	-	BCD-CA-22-005, BCD-CA-22-022, DMND0001221	Annual
5	Enterprise Resource Planning	Sustainment	Shared	1,180	302	1,108	1,410	1,490	BCD-CA-22-016, BCD-CA-22-017, DMND0001213, DMND0001214	Annual
6	Financial Applications Health	Sustainment	Shared	426	292	250	542	250	BCD-CA-22-014, DMND0001224	Annual
7	Human Resources Applications Health	Sustainment	Shared	583	410	250	660	247	BCD-CA-22-004,DMND0001227	Annual
8	Production Growth	Sustainment	Shared	515	517	893	1,410	747	BCD-CA-22-015, DMND0001231	Annual
9	Cloud Health and Safety	Return-to-Health	Shared	-	-	2,518	2,518	582	DMND0001490	Annual
10	Core ERP Data Archiving	Return-to-Health	Shared	-	-	750	750	-	DMND0001217	Annual
11	Source to Pay (S2P) Transformation	Return-to-Health	Shared	-	-	-	-	1,995	DMND0001230	Annual
12	Powerplan Upgrade	IT Enhancements	Shared	1,356	(18)	-	(18)	-	BCD-CA-21-002	Annual
13	SOTeria Safe Worker Observations (SWO)	IT Enhancements	Shared	394	54	-	54	-	BCD-CA-22-012	Annual
14	SuccessFactors Program	IT Enhancements	Shared	187	329	-	329	-	BCD-CA-22-001,DMND0001236	Annual
15	Enterprise Automation	Strategic	Shared	10,158	-	-	-	-	N/A	Annual
16	Enhanced Document Management Capability Projects	Strategic	Shared	-	-	1,218	1,218	2,958	DMND0001448	Annual
17	Organizational Management Optimization	Strategic	Shared	-	-	500	500	-	DMND0001617	Annual
18	SAP Employee Central Payroll	Strategic	Shared	-	-	-	-	864	DMND0001785	Annual
19	Talent System Optimization	Strategic	Shared	-	-	-	-	280	DMND0001619	Annual
20	Transparency Electric Data	Strategic	Electric Only	-	-	1,817	1,817	-	DMND0003095	Annual
21	Projects less than \$250k – Corporate Applications (Shared)	IT Projects<\$250K	Shared	283	212	335	547	-		Annual
22	Projects less than \$250k – Corporate Applications (Elec only)	IT Projects<\$250K	Electric Only	-	-	-	-	-		Annual
23	Total Corporate Applications			17,087	4,518	13,218	17,736	12,375		
24	Shared vs. Electric Only portion									
25	Shared			17,087	4,518	11,401	15,919	12,375		
26	Electric Only			-	-	1,817	1,817	-		
27	Total			17,087	4,518	13,218	17,736	12,375		

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures - IT
Customer Service Projects (\$000)
(Sustainment and Return to Health)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7.2
Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(i)
Line No.	Description	Category	Shared/ Electric Only	Historical	Projected Bridge Period			Projected Test Period	Business Case Reference	In Service Year
				12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025		
1	Automated Application Monitoring Application Health	Sustainment	Shared	589	302	380	682	413	BCD-CS-22-022, DMND0001243	Annual
2	Business Planning and Development (BPD) and Electric Sales & Marketing (ESM) Application Health	Sustainment	Electric Only	386	852	800	1,652	730	BCD-CS-22-013, DMND0001246	Annual
3	Contact Center Application Health	Sustainment	Shared	1,148	1,202	1,250	2,452	1,369	BCD-CS-22-006, DMND0001258	Annual
4	Closed Loop COCL Application Health	Sustainment	Shared	6	1	760	761	835	BCD-CS-22-014, DMND0001255	Annual
5	Cloud Platform Enterprise Agreement	Sustainment	Shared	-	-	750	750	-	DMND0002646	Annual
6	Customer Digital Channels and Self Service Program	Sustainment	Shared	1,550	2,219	2,770	4,989	2,763	BCD-CS-22-016, BCD-CS-22-017, BCD-CS-22-023, BCD-CS-22-024, , DMND0001269, DMND0002741, DMND0001291, DMND0002740	Annual
7	Customer Information Technology (CIT) Configuration Management	Sustainment	Shared	540	574	1,920	2,494	1,057	BCD-CS-22-025, DMND0001253, BCD-CS-22-020	Annual
8	Customer Legacy Application Health	Sustainment	Shared	(202)	668	450	1,118	491	BCD-CS-22-019, DMND0001264	Annual
9	Customer Relationship and Billing Program	Sustainment	Shared	408	550	1,750	2,300	1,916	DMND0001259,DMND0001260, BCD-CS-22-018, BCD-CS-22-026	Annual
10	Hybris Application Health	Sustainment	Electric Only	2,019	2,424	640	3,064	855	BCD-CS-22-012, DMND0001276	Annual
11	MIGreenPower Program Stabilization	Sustainment	Electric Only	435	1,579	1,550	3,129	1,550	DMND0001852, DMND0001680, DMND0001759	Annual
12	Powerley Customer Platform Application Health	Sustainment	Shared	-	2,931	500	3,431	3,750	DMND0002363,DMND0002599	Annual
13	Service Cloud Product Support For Customer Document Submission	Sustainment	Electric Only	-	790	-	790	-	DMND0001289	Annual
14	Supporting capabilities Test data and test data mgmt	Sustainment	Shared	-	-	500	500	500	DMND0001491	Annual
15	Agency Web Site AGW Rebuild	Return-to-Health	Shared	2,669	1,844	-	1,844	-	BCD-CS-22-035	Annual
16	Archive and Purge	Return-to-Health	Shared	1,460	41	-	41	-	BCD-CS-22-052	Annual
17	Contact Center Infrastructure	Return-to-Health	Shared	1,778	663	-	663	-	BCD-CS-22-039	Annual
18	Customer Bill Print and Archive Software	Return-to-Health	Shared	723	-	-	-	-	BCD-CS-21-013	Annual
19	Customer Experience Suite	Return-to-Health	Shared	2,627	518	-	518	-	BCD-CS-22-032	Annual
20	Customer Service Infrastructure Landscape & Growth Project	Return-to-Health	Shared	-	5,947	-	5,947	-	DMND0001263	Annual
21	Digital Channels Transformation Program	Return-to-Health	Shared	502	3,802	4,420	8,222	2,300	BCD-CS-22-034, BCD-CS-22-036, DMND0001250	Annual
22	Distributed Generation Upgrades	Return-to-Health	Electric Only	3,175	60	-	60	-	BCD-CS-21-024	Annual
23	Migrate IVR to the cloud	Return-to-Health	Shared	-	-	2,570	2,570	-	DMND0001538	Annual
24	Systems, Applications, and Products (SAP) Upgrade Program	Return-to-Health	Shared	1,145	3,410	-	3,410	-	BCD-CS-22-033, DMND0001290	Annual
25	Projects < \$250k – Cust Service (Shared)	IT Projects<\$250K	Shared	307	103	-	103	-		Annual
26	Projects < \$250k – Cust Service (Elec only)	IT Projects<\$250K	Electric Only	336	-	-	-	-		Annual
27	Total Customer Service			21,604	30,479	21,010	51,489	18,529		
28	Shared vs. Electric Only portion									
29	Shared			15,252	24,774	18,020	42,794	15,394		
30	Electric Only			6,351	5,705	2,990	8,695	3,135		
31	Total			21,604	30,479	21,010	51,489	18,529		

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Category	Shared/ Electric Only	Historical	Projected Bridge Period			Projected Test	Business Case Reference	In Service Year
				12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025		
1	ACPP/Time of Day	Regulatory/Compliance	Electric Only	10,046	8,000	-	8,000	-	BCD-CS-22-029, DMND0001297	2025
2	Corporate Energy Forecasting	Regulatory/Compliance	Electric Only	294	-	-	-	-	BCD-CS-22-054	Annual
3	Customer Notifications - TCPA Compliance	Regulatory/Compliance	Shared	-	-	300	300	-	DMND0002984	Annual
4	MIGP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	Electric Only	1	413	2,250	2,663	5,493	BCD-CS-22-047, DMND0001265	Annual
5	MIGP - Fixed Price Product(Rider17)	Regulatory/Compliance	Electric Only	2,854	(88)	-	(88)	-	BCD-CS-21-025	Annual
6	MIGP Low Income Solar Pilot	Regulatory/Compliance	Electric Only	-	-	1,242	1,242	785	DMND0001685	Annual
7	MIGP Reservation System for New Enrollments	Regulatory/Compliance	Electric Only	-	1,493	-	1,493	-	DMND0002268	Annual
8	MIGP Website Update	Regulatory/Compliance	Electric Only	1,080	-	-	-	-	BCD-CS-21-019	Annual
9	MIGP Section 61 Settlement	Regulatory/Compliance	Electric Only	3,965	(29)	-	(29)	-	BCD-CS-21-067	Annual
10	MIGP Large Customer Prepayment	Regulatory/Compliance	Electric Only	-	-	-	-	1,327	DMND0001683	Annual
11	MIGP Scope 3 Billing and Enrollment	Regulatory/Compliance	Electric Only	-	-	-	-	3,900	DMND0002493	Annual
12	PCI Compliance	Regulatory/Compliance	Shared	140	102	180	282	176	BCD-CS-22-030, DMND0001282	Annual
13	Payment Stability Plan	Regulatory/Compliance	Shared	427	-	-	-	-	BCD-CS-22-053	Annual
14	Regulatory Compliance	Regulatory/Compliance	Shared	836	2,787	2,770	5,557	2,767	BCD-CS-22-007, DMND0001284	Annual
15	Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial	Regulatory/Compliance	Electric Only	-	398	1,500	1,898	3,000	DMND0001286, DMND0001756, DMND0002604	Annual
16	Securitization	Regulatory/Compliance	Electric Only	267	-	-	-	-	BCD-XX-21-NNN	Annual
17	Treasury Credential on File	Regulatory/Compliance	Shared	1,196	(21)	-	(21)	-	BCD-CS-22-031	Annual
18	Advanced Analytics AA Use Cases Implementation	IT Enhancements	Shared	1,131	457	2,000	2,457	3,009	BCD-CS-22-005, DMND0001241	Annual
19	Automated Application Monitoring Enhancement	IT Enhancements	Shared	1,513	305	-	305	895	BCD-CS-22-015, DMND0001482	Annual
20	Customer Legacy Applications Enhancement	IT Enhancements	Shared	868	(36)	-	(36)	-	BCD-CS-22-011	Annual
21	Customer Relationship and Billing Program Enhancement	IT Enhancements	Shared	2,794	1,196	-	1,196	-	BCD-CS-22-010	Annual
22	IT Application Environments Enhancement	IT Enhancements	Shared	164	320	-	320	-	BCD-CS-22-027, DMND0001275	Annual
23	MDM Stabilization	IT Enhancements	Shared	-	-	-	-	1,802	DMND0002303	Annual
24	Never Billed Accounts due to Theft/Fraud	IT Enhancements	Shared	-	-	-	-	440	DMND0001921	Annual
25	Supporting Capabilities Test Data and Test Data Management	IT Enhancements	Shared	953	(76)	-	(76)	-	BCD-CS-22-038	Annual
26	Transform and Modernize PO Architecture	IT Enhancements	Shared	-	-	-	-	1,025	DMND0001788	Annual
27	Bill Management	Strategic	Shared	3,425	-	-	-	-	BCD-CS-21-058	Annual
28	Billing Web Self-Service	Strategic	Shared	-	590	890	1,480	-	DMND0002368	Annual
29	Collection Web Self-Service	Strategic	Shared	-	2,379	3,500	5,879	2,001	DMND0002367, DMND00002720	Annual
30	Contact Center Enablement	Strategic	Shared	-	889	400	1,289	400	DMND0002370, DMND00002729	Annual
31	Customer Closed Loop Development	Strategic	Shared	314	1,524	-	1,524	-	BCD-CS-22-056, DMND0001254	Annual
32	Customer Service Communication	Strategic	Shared	-	3,852	-	3,852	-	DMND0001262	Annual
33	Customer Service Communication - Phase 2	Strategic	Shared	-	-	2,000	2,000	-	DMND0002730	Annual
34	Enhanced Training Environments	Strategic	Shared	255	-	-	-	-	BCD-CS-21-069	Annual
35	Error Free Communication - Outage Status	Strategic	Electric Only	14,904	13,359	7,563	20,922	-	BCD-CS-21-073, DMND0001695	Annual
36	Field Service Management for RM&P	Strategic	Shared	1,534	96	-	96	-	BCD-CS-22-050	Annual
37	Field Service Management Billing & Metering	Strategic	Shared	831	50	-	50	-	BCD-CS-21-071	Annual
38	IVR Virtual Assistants	Strategic	Shared	1,271	(109)	-	(109)	-	BCD-CS-22-045	Annual
39	Journey Work Product Transformation Teams	Strategic	Shared	6,744	-	-	-	-	BCD-CS-22-042	Annual
40	MIGP Data and Reporting	Strategic	Electric Only	-	906	-	906	-	DMND0001267	Annual
41	MIMO Web Self-Service	Strategic	Shared	-	5,413	3,500	8,913	2,502	DMND0002365, DMND0002721	Annual
42	Payment Web Self-Service	Strategic	Shared	-	51	1,000	1,051	3,502	DMND0002369, DMND0002724	Annual
43	Platform Integration Component	Strategic	Shared	1,048	211	-	211	-	BCD-CS-22-043	Annual
44	Qualtrics Expansion	Strategic	Shared	507	(18)	-	(18)	-	BCD-CS-21-070	Annual
45	SIP in Call Center	Strategic	Shared	-	856	-	856	-	DMND0001293	Annual
46	Speech Analytics	Strategic	Shared	1,145	(28)	-	(28)	-	BCD-CS-21-006	Annual
47	Workforce Automation for Contact Center	Strategic	Shared	1,233	161	-	161	-	DMND0001526	Annual
48	Projects < \$250k - Customer Service	IT Projects<\$250K	Shared	70	43	-	43	-		Annual
49	Projects < \$250k - Customer Service	IT Projects<\$250K	Electric Only	273	40	-	40	-		Annual
50	Total Customer Service			62,082	45,487	29,095	74,582	33,024		

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Category	Shared/ Electric Only	Historical	Projected Bridge Period			Projected Test Period	Business Case Reference
				12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025	
51	Shared vs. Electric Only Projects:								
52	Shared			28,398	20,995	16,540	37,535	18,519	
53	Electric Only			33,684	24,492	12,555	37,047	14,505	
54	Total			62,082	45,487	29,095	74,582	33,024	
55	Summary by Category								
56	Regulatory/Compliance			21,107	13,055	8,242	21,297	17,448	
57	IT Enhancements			7,422	2,166	2,000	4,166	7,171	
58	Strategic			33,210	30,183	18,853	49,036	8,405	
59	IT Projects<\$250K			343	84	-	84	-	
60	Total			62,082	45,487	29,095	74,582	33,024	

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures - IT
Plant and Field Projects (\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7.4
Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
Line No.	Description	Category	Shared/ Electric Only	Historical	Projected Bridge Period			Projected Test	Business Case Reference	In Service Year	
				12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025			
1	GenOpts-FERC Order 841 Compliance	Regulatory/Compliance	Electric Only	-	-	-	-	-	1,296	DMND0001655	Annual
2	Advance Metering Infrastructure (AMI) Application Health	Sustainment	Shared	801	2,247	1,382	3,629	1,376	DMND0001365		Annual
3	ClickSoft Application Health	Sustainment	Shared	2	309	400	709	395	BCD-PFD-22-007, DMND0001373		Annual
4	Distribution Operations Application Health	Sustainment	Electric Only	1,765	1,098	1,180	2,278	1,180	BCD-PFD-22-003, DMND0001380		Annual
5	DTE Electric Generation Capacity Application Health	Sustainment	Electric Only	691	593	570	1,163	563	BCD-PFP-22-004, DMND0001424		Annual
6	DTE Electric Utility Network (UN)	Sustainment	Shared	-	298	370	668	-	DMND0001466		Annual
7	ESRI Application Health	Sustainment	Shared	-	-	441	441	436	DMND0001385		Annual
8	Fuel Supply Application Health	Sustainment	Electric Only	387	383	470	853	469	BCD-PFP-22-006, DMND0001437		Annual
9	ITS-SRS Application Health	Sustainment	Electric Only	-	-	1,050	1,050	520	DMND0002489		Annual
10	ITS ADMS Application Health	Sustainment	Electric Only	-	-	1,070	1,070	1,070	DMND0002490		Annual
11	Network Reliability and Monitoring	Sustainment	Electric Only	-	246	750	996	-	DMND0001396		Annual
12	Nuclear Generation Business Systems Replacement	Sustainment	Electric Only	508	678	650	1,328	648	BCD-PFP-22-001, DMND0001447		Annual
13	Production Growth	Sustainment	Electric Only	9,132	1,486	1,485	2,971	1,292	BCD-PFD-22-019, DMND0001400		Annual
14	Renewable Operations Application Health	Sustainment	Electric Only	115	111	120	231	123	BCD-PFP-22-022, DMND0001995		Annual
15	Supervisory Control and Data Acquisition (SCADA) System Improvement	Sustainment	Electric Only	573	404	520	924	515	BCD-PF-22-001, DMND0001395		Annual
16	System for Fossil Generation for Coal and Gas	Sustainment	Electric Only	394	342	415	757	413	BCD-PFP-22-005, DMND0001436		Annual
17	Advance Metering Infrastructure Field Collection System	Return-to-Health	Shared	2,076	1,243	1,682	2,925	1,678	BCD-PF-22-002, DMND0001366		Annual
18	Cable Routing Application (CRA) Replatform	Return-to-Health	Electric Only	-	-	614	614	-	DMND0001431		Annual
19	Corporate Instance - Maximo Application Suite Upgrade Phase 1	Return-to-Health	Shared	-	-	-	-	3,749	DMND0002451		Annual
20	DO Business Warehouse (DOBW) Replacement	Return-to-Health	Electric Only	-	-	250	250	-	DMND0001376		Annual
21	DO Equipment Engineering Transformer Database	Return-to-Health	Electric Only	-	-	370	370	-	DMND0001381		Annual
22	ESRI Application Health	Return-to-Health	Shared	305	513	-	513	-	BCD-PFD-022-015		Annual
23	Fuel Supply-Plant Fuel Management System	Return-to-Health	Electric Only	-	-	2,127	2,127	-	DMND0001440		Annual
24	Maximo Platform Program	Return-to-Health	Shared	4,051	2,278	1,192	3,470	1,187	BCD-PFD-22-017, DMND0001392		Annual
25	Meter Data Management (MDM) Consolidation	Return-to-Health	Electric Only	13,157	(1,437)	-	(1,437)	-	BCD-PFD-22-018		Annual
26	P3M Heat Rate Calculation and GADS Reporting Functions	Return-to-Health	Electric Only	-	850	-	850	-	DMND0001434		Annual
27	Plant & Field Document Repository	Return-to-Health	Electric Only	3,031	1,395	-	1,395	-	BCD-PF-19-061, DMND0002015		Annual
28	Replace DO Lines - SOC Radio	Return-to-Health	Electric Only	5,160	2,072	-	2,072	-	BCD-PFD-22-025, DMND0002287		Annual
29	DTE Electric Generation Capacity Enhancements	IT Enhancements	Electric Only	1,540	-	-	-	-	BCD-PFP-22-004		Annual
30	Fermi Enhancements	Strategic	Electric Only	421	-	-	-	-	BCD-PFP-22-024		Annual
31	Field Service Management- ClickSoft for EFO (Electric Field Operations)	Strategic	Electric Only	1,057	496	-	496	-	BCD-PF-19-119		Annual
32	Integrated Information Resource (I2R) Replacement	Strategic	Electric Only	12,825	595	-	595	-	BCD-PFP-22-023		Annual
33	Maximo Engineering Process Automation	Strategic	Electric Only	-	3,449	3,757	7,206	-	DMND0001445		Annual
34	Maximo HSE Support	Strategic	Electric Only	-	325	-	325	-	DMND0001433		Annual
35	Primavera Modernization	Strategic	Electric Only	423	(4)	-	(4)	-	DMND0001450		Annual
36	Storm Data Lakehouse	Strategic	Electric Only	-	-	-	-	2,000	DMND0003213		Annual
37	Storm Simulation Lab	Strategic	Electric Only	-	-	6,500	6,500	3,500	DMND0003237		Annual
38	Projects less than \$250k – Plant & Field (Shared)	IT Projects<\$250K	Shared	3	-	-	-	-	DMND0003237		Annual
39	Projects less than \$250k – Plant & Field (Elec only)	IT Projects<\$250K	Electric Only	493	291	60	351	238			Annual
40	Total Plant & Field			58,910	20,261	27,425	47,686	22,648			
41	Shared vs. Electric Only Projects:										
42	Shared			7,237	6,889	5,467	12,356	8,821			
43	Electric Only			51,673	13,372	21,958	35,330	13,827			
44	Total			58,910	20,261	27,425	47,686	22,648			

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line No.	Description	Category	Shared/ Electric Only	Historical 12 mos. ended 12/31/2022	Projected Bridge Period			Projected Test Period 12 mos. ended 12/31/2025	Business Case Reference	In Service Year
					12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024			
1	IT for IT Application Health	Sustainment	Shared	1,669	1,391	16,622	18,013	1,695	BCD-IT-22-009, DMND0001350	Annual
2	IT for IT Tools	IT Enhancements	Shared	254	113	-	113	-	BCD-IT-22-005	Annual
3	Application Portfolio Management - APM	Strategic	Shared	-	438	-	438	-	DMND0001704	Annual
4	Cloud Management (Service Now)	Strategic	Shared	647	(65)	-	(65)	-	BCD-IT-22-011	Annual
5	IT Service Management Tool	Strategic	Shared	1,876	613	-	613	-	BCD-IT-22-008	Annual
6	Projects less than \$250k – IT for IT (Shared)	IT Projects<\$250K	Shared	706	1	-	1	416		Annual
7	Projects less than \$250k – IT for IT (Elec only)	IT Projects<\$250K	Electric Only	-	-	-	-	-		Annual
8	Total Information Technology for IT			5,153	2,491	16,622	19,113	2,111		

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures - IT
Information Protection Security (\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7.6
Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line No.	Description	Category	Shared/ Electric Only	Historical 12 mos. ended 12/31/2022	Projected Bridge Period			Projected Test Period	Business Case Reference	In Service Year
					12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025		
1	Cloud Privilege Access Management	Regulatory/Compliance	Shared	-	416	-	416	500	DMND0001849	Annual
2	Security Information & Event Management (SIEM) End of Life Replacement	Regulatory/Compliance	Shared	-	-	-	-	1,000	DMND0002645	Annual
3	Vendor Onboarding for DTE	Regulatory/Compliance	Shared	-	-	-	-	805	DMND0001869	Annual
4	Vulnerability Scan tool	Regulatory/Compliance	Shared	-	561	425	986	-	DMND0001723	Annual
5	Cloud Security project	Return-to-Health	Shared	0	311	440	751	434	DMND0001344	Annual
6	Cyber Security Defense Center (CSDC) Growth and LifeCycle Management	Return-to-Health	Shared	157	389	300	689	296	BCD-IS-22-003, DMND0001303	Annual
7	IPS Operations PAW and DC Replacement	Return-to-Health	Shared	-	-	320	320	-	DMND0002264	Annual
8	Endpoint Protection	IT Enhancements	Shared	454	287	314	601	316	BCD-IT-22-013, DMND0001359	Annual
9	Automated Provisioning	Strategic	Shared	1,581	762	2,429	3,191	746	BCD-IT-22-014, DMND0001460	Annual
10	Azure Active Directory Federation Implementation	Strategic	Shared	57	299	440	739	439	BCD-IT-21-003, DMND0001342	Annual
11	Cyber Excellence Plan (CEP) Program	Strategic	Shared	310	290	300	590	298	BCD-IS-22-004, DMND0001468	Annual
12	Enterprise Mobility Management	Strategic	Shared	-	179	-	179	333	DMND0001346	Annual
13	Network Access Control	Strategic	Shared	186	32	500	532	1,257	BCD-IT-22-023, DMND0001647	Annual
14	Ransomware Protection	Strategic	Shared	2,538	-	-	-	-	BCD-IT-22-020	Annual
15	Ransomware Recovery	Strategic	Shared	-	418	500	918	500	DMND0001360	Annual
16	Recovery Manager for AD - Disaster Recovery Edition	Strategic	Shared	-	-	664	664	-	DMND0002692	Annual
17	Threat Intel module	Strategic	Shared	524	43	-	43	-	BCD-IT-22-001, DMND0001361	Annual
18	Projects less than \$250k – Info Protection Security (Shared)	IT Projects<\$250K	Shared	256	14	-	14	248		Annual
19	Projects less than \$250k – Info Protection Security (Elec only)	IT Projects<\$250K	Electric Only	-	-	-	-	-		Annual
20	Total Information Protection Security			6,063	4,000	6,632	10,632	7,172		
21	Shared vs. Electric Only Projects:									
22	Shared			6,063	4,000	6,632	10,632	7,172		
23	Electric Only			-	-	-	-	-		
24	Total			6,063	4,000	6,632	10,632	7,172		

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures - IT
Infrastructure Operations (\$000)

Case No.: U-21534
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Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Category	Shared/ Electric Only	Historical 12 mos. ended 12/31/2022	Projected Bridge Period			Projected Test Period	Business Case Reference	In Service Year
					12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025		
1	Automating Database Event Log Monitoring	Regulatory/Compliance	Shared	319	17	-	17	-	BCD-IT-21-014	Annual
2	Tower and Lighting Inspections and Repairs	Regulatory/Compliance	Shared	293	263	150	413	280	BCD-IO-22-017, DMND0001338	Annual
3	Ashley Mews Closure and Relocation	Sustainment	Shared	705	-	-	-	-	BCD-SI-21-002	Annual
4	Backup Environmental Growth	Sustainment	Shared	201	85	624	709	500	BCD-IO-22-007, DMND0001317	Annual
5	Collaboration Application Health	Sustainment	Shared	705	21,783	1,531	23,314	1,523	BCD-CA-22-019, DMND0001211	Annual
6	Dell Storage Hardware Refresh	Sustainment	Shared	-	-	255	255	-	DMND0003143	Annual
7	Endpoint End of Life Electric Support Services	Sustainment	Electric Only	611	973	853	1,826	853	BCD-IO-22-015, DMND0001321	Annual
8	Enterprise Monitoring Licensing Renewal	Sustainment	Shared	-	-	-	-	5,000	DMND0002778	Annual
9	Enterprise Monitoring Strategy Operational Growth	Sustainment	Shared	448	583	600	1,183	1,000	BCD-IO-22-003, DMND0001322	Annual
10	Field Communications Network FCN Growth and Upgrade	Sustainment	Shared	406	384	300	684	400	BCD-IO-22-009, DMND0001324	Annual
11	Network Hardening and Operations	Sustainment	Shared	582	880	400	1,280	400	BCD-IO-22-016, DMND0001334	Annual
12	Palo Alto Capital License Purchase	Sustainment	Shared	-	-	-	-	5,500	DMND0002757	Annual
13	Server Engineering Support Services	Sustainment	Shared	(3,466)	10,000	3,100	13,100	3,100	BCD-IO-22-005, DMND0001336	Annual
14	VMWare License Purchase	Sustainment	Shared	-	-	-	-	5,610	DMND0002871	Annual
15	Compute and Storage Cache Refresh	Return-to-Health	Shared	-	3	528	531	-	DMND0001646	Annual
16	Conference Room Audio Video Support	Return-to-Health	Shared	308	112	500	612	750	BCD-IO-22-006, DMND0001318	Annual
17	Data Center Modernization and Optimization	Return-to-Health	Shared	1,084	941	2,100	3,041	800	BCD-IO-22-002, DMND0001339, DMND0002499	Annual
18	Digital Worker Experience Electric EOL	Return-to-Health	Electric Only	7,889	3,022	2,650	5,672	2,650	BCD-IO-22-013, DMND0001320	Annual
19	End of Life Asset Replacements	Return-to-Health	Shared	6,845	471	500	971	500	BCD-IO-22-010, DMND0001319	Annual
20	Field Worker Device End Of Life	Return-to-Health	Shared	-	-	900	900	900	DMND0002889	Annual
21	Load Balancer Asset Health and Re-Engineering	Return-to-Health	Shared	-	-	-	-	466	DMND0002421	Annual
22	Microwave End Of Life	Return-to-Health	Shared	484	391	402	793	402	BCD-IO-22-008, DMND0001329	Annual
23	Modernize Disaster Recovery Tools	Return-to-Health	Shared	-	-	-	-	500	DMND0002534	Annual
24	Network Advanced Metering Infrastructure Support	Return-to-Health	Shared	2,394	2,076	2,200	4,276	2,200	BCD-IO-22-011, DMND0001330	Annual
25	Network Data Center End of Life Project	Return-to-Health	Shared	402	978	450	1,428	450	BCD-IO-22-019, DMND0001331	Annual
26	Network End of Life Electric	Return-to-Health	Electric Only	397	888	700	1,588	700	BCD-IO-22-018, DMND0001332	Annual
27	Security Infrastructure Growth and EOL	Return-to-Health	Shared	7,416	1,359	1,400	2,759	1,400	BCD-IS-22-002, DMND0001315	Annual
28	Wide Area Network and Wireless Local Area Network Expansion	Return-to-Health	Shared	-	984	600	1,584	1,000	DMND0001732	Annual
29	Virtual Desktop Infrastructure	Return-to-Health	Shared	258	7	-	7	-	BCD-IO-22-022	Annual
30	Virtual Desktop Infrastructure End of Life	Return-to-Health	Shared	-	-	975	975	565	DMND0002397	Annual
31	Afaria Upgrade / Replacement	IT Enhancements	Shared	388	10	-	10	-	BCD-IT-22-012	Annual
32	Network Segmentation (phase 2+) emergent extension	IT Enhancements	Shared	-	588	255	843	400	DMND0001362	Annual
33	Self-healing Endpoint Automation	IT Enhancements	Shared	-	-	-	-	250	DMND0001682	Annual
34	Wide Area Network Redesign Session Initiation Protocol Backhaul	IT Enhancements	Shared	654	128	-	128	-	BCD-IO-22-004	Annual
35	Wireless Local Area Network Expansion	IT Enhancements	Shared	1,260	-	-	-	-	BCD-IO-22-012	Annual
36	ConnectUs Teams	Strategic	Shared	1,905	955	-	955	-	BCD-CA-22-018	Annual
37	Data Power Replacements	Strategic	Shared	-	553	-	553	-	DMND0002223	Annual
38	Data Power Replacement Phase 2	Strategic	Shared	-	-	650	650	-	DMND0001645	Annual
39	Digital Infrastructure and Services	Strategic	Shared	6,408	-	-	-	-	DMND0002356	Annual
40	DTE Private Cloud Infrastructure as a Service	Strategic	Shared	442	571	-	571	-	BCD-IT-22-021, DMND0001356	Annual
41	Endpoint Operating System and Hardware Upgrade	Strategic	Shared	-	-	2,800	2,800	4,100	DMND0001855	Annual
42	Enterprise Monitoring Strategy Implementation	Strategic	Shared	5,000	24	-	24	-	BCD-IT-22-007	Annual
43	External Secure File Transfer Replacement	Strategic	Shared	-	-	355	355	65	DMND0001641	Annual
44	Firewall Threat Protection	Strategic	Shared	-	1,529	600	2,129	-	DMND0001746	Annual
45	Mobile Device Management (MDM)	Strategic	Shared	-	477	340	817	-	DMND0001720	Annual
46	Network Operations Center (NOC) Automation Project	Strategic	Shared	738	36	-	36	-	BCD-IT-22-022	Annual
47	Storm Cloud	Strategic	Electric Only	-	-	10,000	10,000	6,000	DMND0003227	Annual
48	Projects less than \$250k – Infrastructure Ops (Shared)	IT Projects<\$250K	Shared	12	-	-	-	-	-	Annual
49	Projects less than \$250k – Infrastructure Ops (Elec only)	IT Projects<\$250K	Electric Only	-	-	-	-	-	-	Annual
50	Total Infrastructure Operations			45,087	51,074	36,718	87,792	48,264		
51	Shared vs. Electric Only Projects:									
52	Shared			36,190	46,190	22,515	68,706	38,061		
53	Electric Only			8,897	4,884	14,203	19,087	10,203		
54	Total			45,087	51,074	36,718	87,792	48,264		

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures - IT
Enterprise Data Analytics (\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7.8
Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Category	Shared/ Electric Only	Historical 12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	Projected Test Period 12 mos. ended 12/31/2025	Business Case Reference	In Service Year
1	Enterprise Data Platform Application Health	Sustainment	Shared	-	-	1,561	1,561	1,530	DMND0001299	Annual
2	Advance and Enhance the Enterprise Data Platform	IT Enhancements	Shared	5,521	4,000	-	4,000	-	BCD-EDA-22-001	Annual
3	Projects less than \$250k – Ent Data Analytics (Shared)	IT Projects<\$250K	Shared	-	-	-	-	-		
4	Projects less than \$250k – Ent Data Analytics (Elec only)	IT Projects<\$250K	Electric Only	-	-	-	-	-		
5	Total Enterprise Data Analytics			5,521	4,000	1,561	5,561	1,530		
6	<u>Shared vs. Electric Only Projects:</u>									
7	Shared			5,521	4,000	1,561	5,561	1,530		
8	Electric Only			-	-	-	-	-		
9	Total			5,521	4,000	1,561	5,561	1,530		

Michigan Public Service Commission
DTE Electric Company
Capital Expenditures - IT
Innovations (\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.7.9
Witness: P. Sharma
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line No.	Description	Category	Shared/ Electric Only	Historical	Projected Bridge Period			Projected	Business Case Reference	In Service Year
				12 mos. ended 12/31/2022	12 mos. ended 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024	12 mos. ended 12/31/2025		
1	Applied Innovation	Strategic	Shared	2,789	-	-	-	-	BCD-EA-20-002	Annual
2	Projects less than \$250k –Innovations (Shared)	IT Projects<\$250K	Shared	-	-	-	-	-		
3	Projects less than \$250k – Innovations (Elec only)	IT Projects<\$250K	Electric Only	-	-	-	-	-		
4	Total Innovations			2,789	-	-	-	-		
5	Shared vs. Electric Only Projects:									
6	Shared			2,789	-	-	-	-		
7	Electric Only			-	-	-	-	-		
8	Total			2,789	-	-	-	-		

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Corporate Staff
(\$000)

Case No.: U-21534
Exhibit: A-12
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Witness: T. M. Uzenski
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	(a)	(b)	(c)	(d)	(e)	(f)
Capital Expenditures						
Line No.	Description	Historical	Projected Bridge Period		Projected Test Year	
		12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	24 mos. ending 12/31/2024 <i>col. (c)+(d)</i>	12 mos. ending 12/31/2025
1	Electric Vehicle Fleet and Maintenance	43,821	32,791	38,236	71,027	42,600
2	Facilities-Construction & Upgrade (page 2)	50,028	62,969	51,952	114,922	40,492
3	Service Center Optimization & Modernization (page 3)	30,122	40,423	5,793	46,216	28,800
4	Security Measures	5,812	4,222	838	5,059	8,038
5	Other Miscellaneous	(3,185)	(1,524)	150	(1,374)	150
6	Total Corporate Staff	126,597	138,881	96,968	235,849	120,080

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Corporate Staff - Facilities Construction and Upgrades
(\$000)

Case No.: U-21534
Exhibit: A-12
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Witness: T. M. Uzenski
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Line No.	Description	Historical	Projected		In Service Year
		12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	
1	Elevator - BRPP Modernize 2 Freight Elevators	1,309	1,693	-	Annual
2	Elevator - TDC Elevator Modernization	349	31	-	Annual
3	Elevator - MNPP #1 & #3 Freight Elevator Modernization	491	1,186	-	Annual
4	Elevator - SB Freight Modernization	-	788	-	Annual
5	Elevator - MNPP #2 & #4	-	1,019	800	Annual
6	BLRPP, next two elevator modernizations	-	-	-	1,000 Annual
7	WSC Bldg G Roof replacement	2,228	3,962	5,000	- Annual
8	WSC Primary Roof Replacement (Inc. Demo of Cooling Towers)	9	2,913	-	- Annual
9	Trombly SC Roof Replacement	51	1,725	-	- Annual
10	MNPP Transfer House Roofs	-	9	-	500 Annual
11	Belle River Turbine room roofs	-	-	-	1,000 Annual
12	Greenwood Energy Center Roofs	-	82	-	2,000 Annual
13	WCB Substation & Distribution Replacement	485	4,411	5,100	- Annual
14	Plaza Distribution Panelboard Replacement	297	1,868	2,219	5,000 Annual
15	BRPP Turbine Rm OH Crane Modernization	889	205	-	- Annual
16	WCB Chiller Room Decommissioning	177	1,116	-	- Annual
17	ESOC Chiller Replacement	866	1,821	5,000	- Annual
18	WSC North End Tireman Outfall Retention/Detention	140	76	-	- Annual
19	WSC Site Fire Suppression / Eliminate Fire Reservoir	818	3,162	1,300	- Annual
20	WSC Transformer Yard Reorganization	675	2,170	2,913	- Annual
21	GO Façade Restoration	578	1,361	-	- Annual
22	WCB Facade restoration	-	-	-	3,000 Annual
23	WCB Supply and Return Fan Replacement	-	189	-	- Annual
24	Ann Arbor SC - Main building electrical system lifecycle replace	-	9	-	2,000 Annual
25	Redford - Main building electrical system lifecycle replacement	-	-	-	2,000 Annual
26	Renovation - Shelby SC	2,407	5,973	1,000	- Annual
27	Renovation - WCB 1 Conference Rooms	-	4,810	-	- Annual
28	Office space updates - Audio/Video	-	-	4,000	- Annual
29	Office space updates - WCB	-	1,455	1,000	- Annual
30	Office space updates- GO	-	-	1,500	- Annual
31	Office space updates - SB	-	-	1,000	- Annual
32	Office space updates - Plaza	-	-	500	- Annual
33	Renovate Office space - Various	13,087	-	-	- Annual
34	SB Roof Replacement	1,412	-	-	- Annual
35	HREC Roof Replacement	557	1	-	- Annual
36	GO Domestic water piping supply and sanitary replacement	879	-	-	- Annual
37	Edison Center-GO replace update HVAC controls	1,200	-	-	- Annual
38	NAEC Paving East Lot	593	-	-	- Annual
39	UST Program - Ann Arbor SC	35	-	-	- Annual
40	UST Program - Caniff	305	191	-	- Annual
41	GO Stand Pipe Fire Pump Upgrade Revision	141	-	-	- Annual
42	Edison Center-Replace Fire Alarm	9	-	-	- Annual
43	Service Building - Chiller Room Decommissioning	1,076	-	-	- Annual
44	Subtotal	31,064	42,228	31,332	16,500
<u>End of Life Repairs and Replacements</u>					
45	Automotive Lift Program	20	2,995	2,977	1,490 Annual
46	Construction	4,997	4,429	4,403	4,233 Annual
47	Crane	162	269	267	403 Annual
48	Door	905	1,370	1,362	2,054 Annual
49	Electrical	1,860	833	828	1,049 Annual
50	Elevator	36	251	250	377 Annual
51	Environmental	243	9	9	14 Annual
52	Equipment	571	671	667	1,007 Annual
53	Façade	14	615	612	923 Annual
54	Fire	(170)	171	170	257 Annual
55	Flooring	91	221	220	331 Annual
56	HVAC	6,852	6,621	6,582	9,427 Annual
57	Paving	262	-	-	- Annual
58	Plumbing	384	739	734	1,107 Annual
59	Renovation	33	320	318	479 Annual
60	Roofing	889	153	152	229 Annual
61	Safety	190	91	90	136 Annual
62	Security	1,242	163	162	244 Annual
63	Tools	124	82	82	123 Annual
64	Window	47	54	54	81 Annual
65	Other	211	686	682	28 Annual
66	Subtotal	18,963	20,741	20,620	23,992
67	Total Facilities Construction and Upgrade	50,028	62,969	51,952	40,492

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Corporate Staff - Service Center Optimization and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-12
Schedule: B5.8
Witness: T. M. Uzenski
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Line No.	Description	Historical	Projected		In Service Year	
		12 mos. ending 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024		12 mos. ending 12/31/2025
<u>Warren Service Center</u>						
1	WSC DeLab-HVAC Replacement	19	-	-	-	2021
2	Site Improvements	1,155	4,086	1,500	-	2024
3	Building L Renovation	1,362	1,788	-	4,800	2025
4	DeLab Welding Booth Installation	458	3	-	-	2022
5	Building H Demolition	3,022	17	-	-	2022
6	Warren Service Center Total	6,017	5,893	1,500	4,800	
<u>Western Wayne Service Center</u>						
7	Renovation	10,080	4,337	-	-	
8	Garage & Warehouse	-	-	-	4,700	
9	Site Improvements	-	-	-	2,900	
10	Western Wayne Service Center Total	10,080	4,337	-	7,600	2025
11	Waterford Service Center (excluding ASOC)	5,932	25,348	4,293	-	2024
12	Ann Arbor SC Storm Water Improvements	-	-	-	3,000	2025
13	Redford SC Automated Building Control Systems Upgrades	-	-	-	100	2025
14	Caniff SC Automated Building Control Systems Upgrades	-	-	-	100	2025
15	Ann Arbor SC Automated Building Control Systems Upgrades	-	-	-	800	2025
16	Mt. Clemens SC Automated Building Control Systems Upgrades	-	-	-	800	2025
17	Howell SC Automated Building Control Systems Upgrades	-	-	-	600	2025
18	Warren SC Automated Building Control Systems Upgrades	-	-	-	900	2025
19	Lapeer SC Automated Building Control Systems Upgrades	-	-	-	600	2025
20	Newport SC Automated Building Control Systems Upgrades	-	-	-	700	2025
21	NAEC BAS Automated Building Control Systems Upgrades	-	-	-	900	2025
22	Marysville SC Automated Building Control Systems Upgrades	-	-	-	900	2025
23	Training & Development Center Renovation	2	703	-	7,000	2026
24	Training Development Center Site Work	-	205	-	-	2026
25	Caniff Parking Lot Extension	2	155	-	-	2026
26	Farmington Telecommunications Systems Service Center (TSSC)	3,137	1,054	-	-	2023
27	Headquarters HVAC/BMS System	4	2,708	-	-	2024
28	Trombly Annex Demolition, Site Improvements & Garage	452	19	-	-	2022
29	Generation Optimization Relocation	4,497	-	-	-	2022
30	Total Service Center Optimization and Modernization	30,122	40,423	5,793	28,800	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Corporate Staff
(\$000)

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(a)		(b)	(c)
		Adjusted	Projected
		Historical	12 mos. ending
		12 mos. ended	12/31/2025
Line	Description	12/31/2022	
No.			
1	Facilities Construction & Upgrade	776	645
2	Service Center Optimization and Modernization	1,067	1,123
3	Other Corporate	<u>27</u>	<u>27</u>
4	Total AFUDC - Corporate Staff	<u>1,870</u>	<u>1,795</u>

1/ The projected AFUDC amounts are based on the authorized U-21297 of 5.561%

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Corporate Staff
(\$000)

Case No.: U-21534
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Schedule: B5.8
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(a)		**Hide this col. for printing**															(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description	Plant Classification	In-Service Assumption	Capital Expenditures				Est. % Removal	Activity			Activity			Activity																
				(including Removal Costs, net of Salvage)					Accum. Depr. - Removal Costs			Plant in Service			CWIP - Net Additions/(Unitization)																
				12 mos. ended 12/31/2022	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025		12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025	12 mos. ending 12/31/2023	12 mos. ending 12/31/2024	12 mos. ending 12/31/2025														
																	col (d)x(g)	col (e)x(g)	col (f)x(g)												
1	Electric Vehicle Fleet	General Plant, Depreciable	Annual	43,821	32,791	38,236	42,600	0%	-	-	-	32,791	38,236	42,600	-	-	-														
2	Electric Facilities-Repairs/Replacements	General Plant, Depreciable	Annual	18,963	20,741	20,620	23,992	10%	2,074	2,062	2,399	18,667	18,558	21,593	-	-	-														
3	Other Facilities Construction & Upgrade - Decommissioning	General Plant, Depreciable	Annual	1,254	1,116	-	-	100%	1,116	-	-	-	-	-	-	-	-														
4	Other Facilities Construction & Upgrade	General Plant, Depreciable	Annual	29,810	41,112	31,332	16,500	10%	4,111	3,133	1,650	37,001	28,199	14,850	-	-	-														
5	Subtotal Facilities-Const. & Upgrade			50,028	62,969	51,952	40,492	10%	7,302	5,195	4,049	55,668	46,757	36,443	-	-	-														
6	Security	General Plant, Depreciable	Annual	5,812	4,222	838	8,038	0%	-	-	-	4,222	838	8,038	-	-	-														
7	Service Center Optimization and Modernization:																														
8	WSC DeLab-HVAC Replacement	General Plant, Depreciable	Annual	19	-	-	-	10%	-	-	-	-	-	-	-	-	-														
9	Site Improvements	General Plant, Depreciable	Jul-24	1,155	4,086	1,500	-	10%	409	150	-	-	6,067	-	3,677	(4,717)	-														
10	Building L Renovation	General Plant, Depreciable	Dec-25	1,362	1,788	-	4,800	10%	179	-	480	-	-	7,155	1,609	-	(2,835)														
11	DeLab Welding Booth Installation	General Plant, Depreciable	Annual	458	3	-	-	10%	0	-	-	2	-	-	-	-	-														
12	Building H Demolition	General Plant, Depreciable	Annual	3,022	17	-	-	100%	17	-	-	-	-	-	-	-	-														
13	Western Wayne Service Center Total	General Plant, Depreciable	Dec-25	10,080	4,337	-	7,600	10%	434	-	760	-	-	19,815	3,903	-	(12,975)														
14	Waterford Service Center (excluding ASC	General Plant, Depreciable	Jun-24	5,932	25,348	4,293	-	10%	2,535	429	-	-	32,016	-	22,814	(28,153)	-														
15	Trombly Annex Demolition, Site Improver	General Plant, Depreciable	Annual	452	19	-	-	100%	19	-	-	-	-	-	-	-	-														
16	Farmington Telecommunications System	General Plant, Depreciable	Annual	3,137	1,054	-	-	10%	105	-	-	949	-	-	-	-	-														
17	Generation Optimization Relocation	General Plant, Depreciable	Annual	4,497	-	-	-	10%	-	-	-	-	-	-	-	-	-														
18	Training & Development Center Renovati	General Plant, Depreciable	Dec-26	2	703	-	7,000	10%	70	-	700	-	-	-	633	-	6,300														
19	Headquarters HVAC/BMS System	General Plant, Depreciable	Jan-24	4	2,708	-	-	10%	271	-	-	-	2,440	-	2,437	(2,440)	-														
20	Caniff Parking Lot Extension	General Plant, Depreciable	Dec-26	2	155	-	-	10%	16	-	-	-	-	-	140	-	-														
21	Training Development Center Site Work	General Plant, Depreciable	Dec-26	-	205	-	-	10%	21	-	-	-	-	-	185	-	-														
22	Ann Arbor SC Storm Water Improvement	General Plant, Depreciable	Dec-25	-	-	-	3,000	10%	-	-	300	-	-	2,700	-	-	-														
23	Redford SC Automated Building Control S	General Plant, Depreciable	Dec-25	-	-	-	100	10%	-	-	10	-	-	90	-	-	-														
24	Caniff SC Automated Building Control Sy	General Plant, Depreciable	Dec-25	-	-	-	100	10%	-	-	10	-	-	90	-	-	-														
25	Ann Arbor SC Automated Building Contrc	General Plant, Depreciable	Dec-25	-	-	-	800	10%	-	-	80	-	-	720	-	-	0														
26	Mt. Clemens SC Automated Building Con	General Plant, Depreciable	Dec-25	-	-	-	800	10%	-	-	80	-	-	720	-	-	0														
27	Howell SC Automated Building Control S	General Plant, Depreciable	Dec-25	-	-	-	600	10%	-	-	60	-	-	540	-	-	-														
28	Warren SC Automated Building Control S	General Plant, Depreciable	Dec-25	-	-	-	900	10%	-	-	90	-	-	810	-	-	-														
29	Lapeer SC Automated Building Control S	General Plant, Depreciable	Dec-25	-	-	-	600	10%	-	-	60	-	-	540	-	-	-														
30	Newport SC Automated Building Control :	General Plant, Depreciable	Dec-25	-	-	-	700	10%	-	-	70	-	-	630	-	-	(0)														
31	NAEC BAS Automated Building Control S	General Plant, Depreciable	Dec-25	-	-	-	900	10%	-	-	90	-	-	810	-	-	-														
32	Marysville SC Automated Building Contrc	General Plant, Depreciable	Dec-25	-	-	-	900	10%	-	-	90	-	-	810	-	-	-														
33	Subtotal SCO			30,122	40,423	5,793	28,800		4,074	579	2,880	951	40,523	35,430	35,398	(35,310)	(9,510)														
34	NERC-Critical Infrastructure Program	Intangible Plant, 5 year	Annual	5	-	-	-	0%	-	-	-	-	-	-	-	-	-														
35	Miscellaneous Corporate:																														
36	Investment Recovery Salvage Sales	General Plant, Depreciable	Annual	(4,525)	(2,369)	(2,208)	(2,208)	100%	(2,369)	(2,208)	(2,208)	-	-	-	-	-	-														
37	Corporate Services-Misc Other	General Plant, Depreciable	Annual	511	531	416	416	0%	-	-	-	531	416	416	-	-	-														
38	Other Misc Corporate	General Plant, Depreciable	Annual	823	314	1,942	1,942	0%	-	-	-	314	1,942	1,942	-	-	-														
39	Total Capital Projects			126,597	138,881	96,968	120,080		9,007	3,567	4,721	94,476	128,711	124,869	35,398	(35,310)	(9,510)														

**Michigan Public Service Commission
DTE Electric Company
Charging Forward Expansion Cost Projections
(\$000)**

Case No.: U-21534
Exhibit: A-12
Schedule: B5.9
Witness: P. Bennett
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Description	Historical 12 mos. ended 12/31/2022	Projected Bridge Period		Bridge Period 24 mos. ending 12/31/2024	Test Period 12 mos. ending 12/31/2025
			12 mos. ending 12/31/2023	12 mos. ending 12/31/2024		
1	Projected Capital Expenditures					
2	Program Administration	15	223	171	394	-
3	Business and eFleet Charger Rebates	-	155	4,264	4,419	-
4	Home Charger Installation		520	-	520	-
5	Business Charger Installation	-	-	1,274	1,274	-
6	Charging Hubs	-	96	1,800	1,896	3,500
7	eFleet Battery Support	-		5,000	5,000	-
8	TEP IT Capabilities	-	-	-	-	1,600
9	Total Capital Expenditures	\$ 15	\$ 994	\$ 12,509	\$ 13,503	\$ 5,100
10	Projected O&M Expenditures					
11	Education & Outreach O&M	-	233	1,500	1,733	1,500
12	Program Administration O&M	-	688	793	1,481	1,752
13	Total O&M Expenditures	\$ -	\$ 922	\$ 2,293	\$ 3,214	\$ 3,252
14	Projected Regulatory Asset Costs					
15	Program Administration	950	699	849	1,548	-
16	Education & Outreach	1,216	802	300	1,102	-
17	Residential Customer Rebates	655	1,828	2,000	3,827	3,126
18	Business and eFleet Charger Rebates	2,599	2,772	7,732	10,504	16,002
19	Business Charger Installations	-	-	2,041	2,041	-
20	Additional Elements	564	-	-	-	-
21	Emerging Tech Fund	-	825	1,000	1,825	1,000
22	School Bus Chargers	-	-	2,000	2,000	-
23	Total Regulatory Asset Costs	\$ 5,985	\$ 6,927	\$ 15,922	\$ 22,848	\$ 20,128
24	Total Costs	\$ 6,000	\$ 8,842	\$ 30,724	\$ 39,566	\$ 28,480

Michigan Public Service Commission
DTE Electric Company
Projected Net Operating Income
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C1
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b) Source	(c) Historical Net Operating Income Ending 12/31/22	(d) Projection Adjustments	(e) Projected Net Operating Income Ending 12/31/2025
1	Operating Revenues	Exh. A-13, Sch. C3	5,176,971	288,445	5,465,416
2	<u>Operating Expenses</u>				
3	Fuel and Purchased Power	Exh. A-13, Sch. C4	1,395,778	(41,673)	1,354,105
4	Operations and Maintenance Expenses	Exh. A-13, Sch. C5	1,224,438	42,512	1,266,950
5	Depreciation and Amortization	Exh. A-13, Sch. C6	1,056,156	210,089	1,266,245
6	Property Taxes	Exh. A-13, Sch. C7, C7.1	265,899	62,874	328,772
7	Other Taxes	Exh. A-13, Sch. C7	49,175	4,005	53,180
8	State & Local Income Taxes	Exh. A-13, Sch. C9, C10	66,766	(5,353)	61,413
9	Federal Income Taxes	Exh. A-13, Sch. C8	27,336	80,440	107,776
10	Other Utility (Income)/Deductions	Exh. A-13, Sch. C13	(6,400)	-	(6,400)
11	Total Operating Expenses		4,079,148	352,893	4,432,041
12	Operating Income		1,097,823	(64,448)	1,033,375
13	<u>Operating Income Adjustments</u>				
14	Allowance for Funds Used During Construction	Exh. A-13, Sch. C11	37,473	18,497	55,969
15	Loss on Reacquired Securities	Exh. A-13, Sch. C12	(3,310)	1,066	(2,244)
16	Total Operating Income Adjustments		34,162	19,563	53,726
17	Adjusted Net Operating Income		1,131,985	(44,885)	1,087,100

Michigan Public Service Commission
DTE Electric Company
Projected Net Operating Income Adjustments
For the 12 Months Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C1.1
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description	Source Exhibit	Revenues	Fuel & Purch Pwr	O&M	Deprec and Amort	Property Taxes	Other Taxes	State & Local Income Taxes	Federal Income Taxes	AFUDC	Other Inc./ (Ded.)	Adjusted NOI
Historical Year Ended December 31, 2022													
1	Adjusted Normalized Historical Net Operating Income	A-3 C1	5,176,971	1,395,778	1,224,439	1,056,155	265,899	49,175	66,766	27,336	37,473	3,090	1,131,985
2	Projection Adjustments												
3	Revenues	A-13 C3	288,445						17,912	56,812			213,721
4	Fuel and Purchased Power	A-13 C4		(41,673)					2,588	8,208			30,877
5	O&M	A-13 C5			42,512				(2,640)	(8,373)			(31,499)
6	Depreciation and Amortization	A-13 C6				210,089			(13,047)	(41,379)			(155,663)
7	Property Taxes	A-13 C7					62,874		(3,904)	(12,384)			(46,586)
8	Other Taxes	A-13 C7						4,005	(249)	(789)			(2,967)
9	State & Local Income Taxes	A-13 C9, C10							(5,790)				5,790
10	Federal Income Taxes	A-13 C8								79,054			(79,054)
11	Allowance for Funds Used During Construction	A-13 C11							345	1,096	18,497		17,056
12	Loss on Reaquired Securities	A-13 C12							66	210		1,066	790
13	Other Deductions	A-13 C13							-	-		-	-
14	Income Tax Effect of Interest	A-13 C14							(594)	(1,884)			2,478
15	Synchronization Adjustment	A-13 C15							(41)	(131)			172
16	Total Projection Adjustments		288,445	(41,673)	42,512	210,089	62,874	4,005	(5,353)	80,440	18,497	1,066	(44,885)
17	Net Operating Income	L1+L16	<u>5,465,416</u>	<u>1,354,105</u>	<u>1,266,951</u>	<u>1,266,244</u>	<u>328,773</u>	<u>53,180</u>	<u>61,414</u>	<u>107,776</u>	<u>55,969</u>	<u>4,157</u>	<u>1,087,100</u>

Michigan Public Service Commission
DTE Electric Company
Projected Revenue Conversion Factor
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21534
 Exhibit: A-13
 Schedule: C2
 Witness: K. M. Vangilder
 Page: 1 of 1

	(a)	(b)	(c)
Line No.	Description	Calculation	Amount
1	Income Before Income Taxes		100.00
2	Michigan Corporate Income Tax Rate	(1)	5.88%
3	Composite Municipal Income Tax Rate		<u>0.33%</u>
4	Total State and Local Tax Rates	L2+L3	6.21%
5	Federal Income Tax Base	L1 - (L4x100)	93.79
6	Federal Income Tax Rate		<u>21.00%</u>
7	Federal Income Tax	L5 x L6	<u>19.70</u>
8	Income after Federal, Michigan and Municipal Taxes	L5 - L7	<u>74.09</u>
9	Revenue Conversion Factor	L1 / L8	<u><u>1.3496</u></u>

(1) 6% Statutory rate at 98.00% apportionment as supported by Witness Wisniewski

Michigan Public Service Commission
DTE Electric Company
Projected Operating Revenue
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C3
 Witness: T. M. Uzenski
 Page: 1 of 3

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Adj. Historical 12 mos. ended 12/31/22	Projection Adjustments	Test 12 mos. ending 12/31/25	Reference
1	Electric Sales Revenue	3,671,417	324,559	3,995,976	
2	Base Fuel and Purchased Power Revenue	1,395,778	(41,673)	1,354,105	Witness Willis Exh. A-13 C4
3	Electric Sales Revenue (440-449.1, 456.1)	5,067,194	282,886	5,350,080	Exh. A-13, Sch. C3, page 2, line 8
4	Sales for Resale (447)	0	(0)	-	
5	Other Operating Revenues (450-456)	102,025	5,559	107,584	Detailed below on Lines 9 thru 17
6	Other Revenue Adjustment:				
7	R2 Special Purpose Facilities Rider	7,751	(0)	7,751	Witness Maroun WP A-16 F1, Schedule 16
8	Total Operating Revenue	5,176,971	288,445	5,465,416	
9	<u>Other Operating Revenues (450-456)</u>				
10	Late Payment Charges (450)	16,045	-	16,045	
11	Misc Service Charges (451)	8,888	0	8,888	
12	Sale of Water (453)	-	-	-	
13	Electric Property Rental (454)	16,328	(0)	16,328	
14	Interdept Rent/Shared Asset Rev (455)	57,939	5,559	63,498	Exh. A-13, Sch. C3, page 3, line 3
15	Other Misc Rev (456)	2,260	(0)	2,260	
16	Transmission of Others Elec (456.1)	566	0	566	
17	Total Misc Operating Revenue	102,025	5,559	107,584	

Michigan Public Service Commission
DTE Electric Company
Operating Revenue
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case: U-21534
 Exhibit: A-13
 Schedule: C3
 Witness: T. M. Uzenski
 Page: 2 of 3

(a)		(b)	(c)
Line No.	Description	Test 12 mos. ending 12/31/25	Reference
1	Total Electric Sales Revenue	5,561,302	1/
2	Less: Nuclear Surcharge Revenue	38,792	
3	Securitization Surcharge Revenue	-	
4	Energy Waste Reduction Surcharge Revenue	124,688	
5	Renewable Program Surcharge Revenue	-	Renewable surcharge rate is zero
6	Infrastructure Redesign and Modernization (IRM) Surcharge Revenue	23,536	
7	Low Income Energy Assistance Fund (LIEAF) Surcharge Revenue	<u>24,206</u>	
8	Electric Sales Revenue excluding Surcharges	<u><u>5,350,080</u></u>	Line 1 less Lines 2 through 7

1/ Sponsored by Witness Willis on Exhibit A-16, Schedule F2, Page 2, Line 49, Column (b)

Michigan Public Service Commission
DTE Electric Company
Interdepartment Rent / Shared Asset Revenue
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case: U-21534
 Exhibit: A-13
 Schedule: C3
 Witness: T. M. Uzenski
 Page: 3 of 3

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Adj. Historical 12 mos. ended 12/31/22	Projection Adjustments	Test 12 mos. ending 12/31/25	Reference
1	Shared Asset Revenue	56,924	5,839	62,763	Workpaper TMU-13
2	C360 "Return on" Cross Charge to DTE Gas	1,016	(280)	735	
3	Total Interdepartment Rent (Account 455)	57,939	5,559	63,498	

Michigan Public Service Commission
DTE Electric Company
Calculation of Power Supply Expenses
Projected 12 Month Period Ending Dec. 31, 2025

Case No.: U-21534
Exhibit: A-13
Schedule: C4
Witness: A. Willis
Page: 1 of 1

Line No.	(a) Description	(b) Amount	(c) Source
1	Current PSCR Base including transmission at generation level (mills/kWh)	31.26	U-15768; Exh. A-10, Sch. C4
2	Loss Factor (mills/kWh)	1.0769	Exhibit A-13, Schedule C4.1, Col (d) Line 6
3	PSCR Base including transmission at sales level (mills/kWh)	33.66	(Line 1 x Line 2)
4			
5	DTE Electric Power Supply Projected Sales (MWh)	39,755,689	Exhibit A-15, Schedule E1, Page 2 column F
6			
7	Transmission Expense	\$ 305,671,000	U-15768; Exh. A-10, Sch. C4.3
8			
9	Base Transmission Expense at PSCR Sales Level (mills/kWh)	7.69	(Line 7 ÷ Line 5)
10			
11	Base Fuel & PP Expense at PSCR Sales Level (mills/kWh)	25.97	(Line 3 - Line 9)
12			
13	<u>Test Year Power Supply Costs (Less Transmission)</u>		
14			
15	DTE Electric Power Supply Projected Sales (MWh)	39,755,689	Line 5
16	DTE Electric R10 & R3 MISO Pricing Option Projected Sales (MWh)	1,005,467	Exhibit A-16, Schedule F3 (R3 & R10 MISO energy charge sales)
17	DTE Electric D13 Projected Sales (MWh)	200,000	Exhibit A-16, Schedule F3, Rate Schedule D13 Detail
18	DTE Electric Retail Sales (less R10, R3, & D13) (MWh)	38,550,222	
19			
20	DTE Electric Retail Power Supply Costs (less R10, R3, and D13)	\$ 1,001,197,990	(Line 18 x Line 11)
21	MISO Pricing Option Costs (Note 1)	\$ 39,565,126	(Line 16 x \$39.35/MWh)
22	R10 Voltage Level Service Adder	\$ 810,579	Exhibit A-16, Schedule F3 (R10 voltage level detail)
23	D13 Non Capacity	\$ 6,860,000	Exhibit A-16, Schedule F3, Rate Schedule D13 Detail
24	DTE Electric Total Power Supply Costs	\$ 1,048,433,696	
25			
26	R10 and R3 Transmission	\$ 7,730,770	Line 9 x Line 16
27	D13 Transmission	\$ 616,000	Line 17 x D13 Transmission (\$3.08/MWh)
28	PSCR Sales Transmission	\$ 297,324,230	(Line 29 - Line 26)
29	Transmission Expense	\$ 305,671,000	
30			
31	Total Expense	\$ 1,354,104,696	
32			
33			
34	Capacity and Non-Capacity Detail		
35			
36	Non-Capacity Power Supply Expenses	\$ 2,199,398,007	
37	PA295 Capacity Related Generation Cost	\$ 130,469,507	Exhibit A-26 Schedule P2
38	PURPA Capacity Related Generation Cost	\$ 8,892,095	Exhibit A-26 Schedule P1
39	Capacity Purchases	\$ (1,307,890)	Exhibit A-26 Schedule P3
40	Net Energy Market Sales Revenue	\$ (983,347,023)	Exhibit A-26 Schedule P3
41	Total Power Supply Expense	\$ 1,354,104,696	

Note 1 - Average MISO Wholesale Purchase cost for test period as supported in Case U-21050 Exhibit A-6

Michigan Public Service Commission
DTE Electric Company
Calculation of 5 Year Average Line Loss Factor

Case No. : U-21534
Exhibit: A-13
Schedule: C4.1
Witness: A. Willis
Page: 1 of 1

	(a)	(b)	(c)	(d)
Line No.	Year	System Output ¹ <u>GWh</u>	Annual Sales ² <u>GWh</u>	Loss Factor <u>%</u>
1	2018	52,172	48,527	7.51%
2	2019	50,116	46,623	7.49%
3	2020	47,851	44,381	7.82%
4	2021	49,380	45,839	7.72%
5	2022	48,985	45,383	7.94%
6	Average	49,701	46,151	7.69%

Source: Gross Margin Group

1. NSO from GOBIR240 report and Leuker Exhibit A-15 Schedule E2
2. Annual Sales from FODS report (Revenue Package report).

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Summary
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
							Projected Adjustments					
			1/1/22 -				1/1/23 -	1/1/24 -	1/1/25 -			
Line		Exhibit	12/31/22	Rate Case	Normalization	Adjusted	12/31/23	12/31/24	12/31/25	Other	Total	Projected
No.	Description	A-13	Historical	Adjustments	Adjustments	Historical	Inflation	Inflation	Inflation	Adjustments	Projected	Test Period
			Test Period			Test Period	Adjustment	Adjustment	Adjustment		Adjustments	
1	Steam Power Generation	C5.1	203,919	19,296	-	223,215	7,143	6,680	6,874	(30,507)	(9,809)	213,406
2	Fuel Supply & MERC Fuel Handling	C5.2	2,294	6,007	-	8,302	266	248	256	(956)	(186)	8,115
3	Nuclear Power Generation	C5.3	220,346	(28,555)	(0)	191,791	5,136	4,804	4,943	(47,308)	(32,424)	159,366
4	Hydraulic Power Generation	C5.4	10,266	-	-	10,266	329	307	316	-	952	11,218
5	Other Power Generation	C5.5	60,658	(37,726)	-	22,932	734	686	706	6,426	8,553	31,485
6	Distribution	C5.6	352,844	(14,723)	(2,864)	335,257	7,348	6,872	7,072	2,660	23,952	359,210
7	Customer Service	C5.7	309,310	(196,876)	-	112,435	3,128	2,925	3,010	(2,873)	6,190	118,625
8	Uncollectible Accounts Expense	C5.8	35,199	-	-	35,199	-	-	-	15,671	15,671	50,870
9	Regulated Marketing	C5.9	20,536	-	-	20,536	653	611	629	9,725	11,618	32,154
10	Corporate Support	C5.10	223,216	(29,163)	(10,680)	183,372	5,132	4,800	4,939	-	14,871	198,243
11	Pension and Benefits	C5.11	89,939	(3,936)	(4,869)	81,134	-	-	-	3,125	3,125	84,259
12	Total O&M Expense		<u>1,528,528</u>	<u>(285,675)</u>	<u>(18,413)</u>	<u>1,224,440</u>	<u>29,869</u>	<u>27,935</u>	<u>28,745</u>	<u>(44,037)</u>	<u>42,510</u>	<u>1,266,950</u>

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Steam Power Generation
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.1
Witness: M. E. Guillaumin
Page: 1 of 1

Line No.	(a) Description	(b) Account	(c) 1/1/22 - 12/31/22 Historical Test Period	(d) Rate Case Adjustments Reclass Fuel Handling to O&M 2/	(e) Reclass MERC Fuel Handling Non-O&M Expense 3/	(f) Historical Adjustments 4/	(g) Adjusted Historical Test Period	(h) 1/1/23 - 12/31/23 Inflation Adj 5/	(i) 1/1/24 - 12/31/24 Inflation Adj 5/	(j) 1/1/25 - 12/31/25 Inflation Adj 5/	(k) Other Adjustments 6/	(l) Total Projected Adjustments	(m) Projected Test Period
1	Steam Power Generation						sum (c) thru (f)					sum (h) thru (k)	(g) + (l)
2	Operation												
3	Operation Supervision and Engineering	500	10,936	-	-	-	10,936	350	327	337	(499)	515	11,451
4	Fuel Handling	501	-	30,979	(5,577)	-	25,402	813	760	782	-	2,355	27,758
5	Steam Expenses	502	16,233	-	-	-	16,233	519	486	500	(2,502)	(996)	15,236
6	Steam from Other Sources	503	-	-	-	-	-	-	-	-	-	-	-
7	(Less) Steam Transferred-Cr.	504	-	-	-	-	-	-	-	-	-	-	-
8	Electric Expenses	505	3,555	-	-	-	3,555	114	106	109	(1,706)	(1,376)	2,179
9	Misc Steam Power Expenses	506	49,209	-	-	(99)	49,110	1,572	1,470	1,512	(10,952)	(6,399)	42,711
10	Rents	507	-	-	-	-	-	-	-	-	-	-	-
11	Total Operation Expense		79,932	30,979	(5,577)	(99)	105,236	3,368	3,149	3,241	(15,659)	(5,901)	99,335
12	Maintenance												
13	Maintenance Supervision and Engineering	510	443	-	-	-	443	14	13	14	(4)	37	480
14	Maintenance of Structures	511	11,247	-	-	-	11,247	360	337	346	(2,720)	(1,677)	9,571
15	Maintenance of Boilers	512	59,026	-	-	-	59,026	1,889	1,767	1,818	(7,243)	(1,770)	57,256
16	Maintenance of Electric Plant	513	9,664	-	-	-	9,664	309	289	298	(1,762)	(866)	8,798
17	Maintenance of Misc Steam Plant	514	45,900	-	-	-	45,900	1,469	1,374	1,414	(4,075)	181	46,081
18	Total Maintenance Expense		126,281	-	-	-	126,281	4,041	3,779	3,889	(15,804)	(4,095)	122,186
19	Total Steam Power Generation		206,213	30,979	(5,577)	(99)	231,516	7,409	6,929	7,130	(31,463)	(9,996)	221,521
20	Less Fuel Supply & MERC Fuel Handling	1/	2,294	11,584	(5,577)	-	8,302	266	248	256	(956)	(186)	8,115
21	Total Steam excluding Fuel Supply & MERC		203,919	19,395	-	(99)	223,215	7,143	6,680	6,874	(30,507)	(9,809)	213,406

1/ Reclassify Fuel Supply and MERC Fuel Handling sponsored by Witness Milo on Exh A-13, C5.2

2/ Reclassify Fuel Handling O&M charged to Fuel Account 501

3/ Portion of MERC Fuel Handling Charge that is reallocated to other line item classifications within net operating income (see Witness Milo's Exh A-13, C5.2)

4/ Historical Adjustments:	Account	Amount
Corporate Membership Adjustment - EEI	506 & 921	(99)
		(99)

	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
5/ Annual Inflation Rate	3.20%	2.90%	2.90%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.20%	2.90%	2.90%
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)			

6/ Projected Adjustments	Account	Amount
St. Clair Power Plant Closing	500, 502, 505, 506, 511, 512, 513, 514	(18,320)
Trenton Channel Power Plant Closing	500, 502, 505, 506, 510, 511, 512, 513, 515	(13,143)
		(31,463)

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Fuel Supply & Midwest Energy Resources Company (MERC)
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.2
Witness: D. C. Milo
Page: 1 of 1

Line No.	(a) Description	(b) Account	(c) 1/1/22 - 12/31/22 Historical Test Period	(d) Rate Case Adjustments		(f) Adjusted Historical Test Period	(g) Projected Adjustments			(j) Other Adjustments 4/	(k) Total Projected Adjustments	(l) Projected Test Period
				(e) Reclass Fuel Handling to O&M 1/	(e) Reclass MERC Fuel Handling Non-O&M Expense 2/		(g) 1/1/23 - 12/31/23 Inflation Adj 3/	(h) 1/1/24 - 12/31/24 Inflation Adj 3/	(i) 1/1/25 - 12/31/25 Inflation Adj 3/			
						sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
1	Fuel Supply											
2	Operation Supervision and Engineering	500	620	-	-	620	20	19	19	-	57	678
3	Fuel Handling	501	-	2,157	-	2,157	69	65	66	-	200	2,357
4	Misc Steam Power Expenses	506	246	-	-	246	8	7	8	-	23	269
5	Maintenance Supervision and Engineering	510	105	-	-	105	3	3	3	-	10	115
6	Maintenance of Misc Steam Plant	514	1,323	-	-	1,323	42	40	41	-	123	1,446
7	Total Fuel Supply		2,294	2,157	-	4,451	142	133	137	-	413	4,864
8	MERC Fuel Handling											
9	O&M			3,850	-	3,850	123	115	119	(956)	(599)	3,251
10	Depreciation			3,952	(3,952)	-	-	-	-	-	-	-
11	Property Taxes			975	(975)	-	-	-	-	-	-	-
12	Payroll Taxes			169	(169)	-	-	-	-	-	-	-
13	Income Taxes			(14)	14	-	-	-	-	-	-	-
14	Interest Expense			494	(494)	-	-	-	-	-	-	-
15	Total MERC Fuel Handling	501		9,427	(5,577)	3,850	123	115	119	(956)	(599)	3,251
16	Total Fuel Supply & MERC Fuel Handling		2,294	11,584	(5,577)	8,302	266	248	256	(956)	(186)	8,115

1/ Reclassify Fuel Supply's Fuel Handling O&M charged to Fuel Account 501

2/ MERC fuel handling is reallocated to the proper line item classification within net operating income as shown on Exhibit A-3 C16 sponsored by Witness Uzenski.

	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
3/ Annual Inflation Rate	3.20%	2.90%	2.90%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.20%	2.90%	2.90%
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)			

4/ Projected savings from reduced operations as transshipments decrease

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Nuclear Power Generation
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.3
Witness: J. C. Davis
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			Rate Case Adjustments				Projected Adjustments							
			1/1/22 - 12/31/22	Nuclear	Reclassify	Historical	Adjusted	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25	Outage	PERC	Total	
Line	Description	Account	Historical	Surcharge	PERC	Adjustments 2/	Historical	Inflation Adj	Inflation Adj	Inflation Adj	Accrual	Amortization	Projected	Projected
No.			Test Period	1/			Test Period	3/	3/	3/	4/	5/	Adjustments	Test Period
1	Nuclear Power Generation						sum (c) thru (f)						sum (h) thru (l)	(g) + (m)
2	Operation													
3	Operation Supervision and Engineering	517	13,466	(183)	-	-	13,282	425	398	409	-	-	1,232	14,514
4	Coolants and Water	519	2,341	1	-	-	2,342	75	70	72	-	-	217	2,559
5	Steam Expenses	520	3,115	(5,228)	(7)	-	(2,121)	(68)	(63)	(65)	(8,977)	-	(9,173)	(11,294)
6	Steam from Other Sources	521	-	-	-	-	-	-	-	-	-	-	-	-
7	(Less) Steam Transferred-Cr.	522	-	-	-	-	-	-	-	-	-	-	-	-
8	Electric Expenses	523	4,506	-	-	-	4,506	144	135	139	-	-	418	4,924
9	Misc Nuclear Power Expenses	524	74,982	(23,001)	(2,554)	-	49,427	1,582	1,479	1,522	-	-	4,583	54,010
10	Rents	525	-	-	-	-	-	-	-	-	-	-	-	-
11	Station Expense	562	53	-	-	-	53	2	2	2	-	-	5	57
12	Total Operation Expense		98,462	(28,412)	(2,561)	-	67,489	2,160	2,020	2,078	(8,977)	-	(2,719)	64,770
13	Maintenance													
14	Maintenance Supervision and Engineering	528	22,295	-	-	-	22,295	713	667	687	-	-	2,067	24,362
15	Maintenance of Structures	529	25,434	-	-	-	25,434	814	761	783	-	-	2,358	27,792
16	Maintenance of Reactor Plant Equipment	530	28,630	(140)	(19,962)	-	8,528	273	255	263	(26,930)	-	(26,139)	(17,611)
17	Maintenance of Electric Plant	531	35,486	(3)	(8,703)	-	26,780	857	801	825	-	-	2,483	29,263
18	Maintenance of Misc Nuclear Plant	532	10,040	-	(49)	-	9,991	320	299	308	-	-	926	10,917
19	Maintenance of station equipment	570	-	-	-	-	-	-	-	-	-	-	-	-
20	Total Maintenance Expense		121,884	(143)	(28,714)	-	93,027	2,977	2,784	2,865	(26,930)	-	(18,304)	74,723
	PERC Regulatory Asset													
21	PERC Base Expense		-	-	15,000	(0)	15,000	-	-	-	-	-	-	15,000
hide	Reg Asset Amort-PERC (530 a need for COS	530	-	-	8,138	-	8,138	-	-	-	-	(5,701)	(5,701)	2,437
hide	Reg Asset Amort-PERC (531 a need for COS	531	-	-	8,138	-	8,138	-	-	-	-	(5,701)	(5,701)	2,437
22	Reg Asset Amortization-PERC		-	-	16,275	-	16,275	-	-	-	-	(11,402)	(11,402)	4,873
23	Total PERC Expense		-	-	31,276	(0)	31,275	-	-	-	-	(11,402)	(11,402)	19,873
24	Total Nuclear Power Generation		220,346	(28,555)	-	(0)	191,791	5,136	4,804	4,943	(35,906)	(11,402)	(32,424)	159,366

1/ Eliminate O&M expenses recovered separately in Nuclear Surcharge

Amount	Account
Site Security (16,549)	524
Radiation Protection (12,006)	517-520,524 ,530,531
(28,555)	

3/ Annual Inflation Rate
No. of Months in Period
Pro-rated Inflation Rate
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)

1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
3.20%	2.90%	2.90%
12	12	12
3.20%	2.90%	2.90%

2/ Historical Adjustments:

Amount	Account

4/ Outage Accrual Projection Adjustment:

Amount	Account
Outage Accrual Steam Expense (8,977)	520
Outage Accrual Reactor Plant Maint. (26,930)	530
Total Outage Accrual (35,906)	

5/ PERC (Performance Evaluation Review Committee) regulatory asset amortization sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.17

Michigan Public Service Commission
DTE Electric Company
O&M Expense - Nuclear Power Generation
Historical Test Year
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.3
Witness: J. C. Davis
Page: 2 of 2

(a)		(b)
Line No.	Organization	Adjusted Historical 12 Months Ended 12/31/22
1	Nuclear Organization	94,304
2	PERC Base Expense	15,000
3	Reg Asset Amortization - PERC	16,275
4	Regulatory Assessments and Dues	12,761
5	Nuclear Organization - Base	138,341
6	Refueling Outage	
7	Refuel Outage	73,100
8	Refuel Outage Accrual	18,350
9	Refuel Outage Reversal	(38,000)
10	Total Refueling Outage	53,450
11	Total Nuclear Generation	191,791
12	FERC Account Summary	
13	Operating FERC Accounts	67,489
14	Maintenance FERC Accounts	124,302
15	Total Nuclear FERC Accounts	191,791

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Hydraulic Power Generation
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.4
Witness: M. E. Guillaumin
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Description	Account	1/1/22 - 12/31/22 Historical Test Period	Rate Case Adjustments	Adjusted Historical Test Period	Projected Adjustments			Other Adjustments	Total Projected Adjustments	Projected Test Period
						1/1/23 - 12/31/23 Inflation Adj 1/	1/1/24 - 12/31/24 Inflation Adj 1/	1/1/25 - 12/31/25 Inflation Adj 1/			
1	Hydraulic Power Generation				sum (c) thru (d)					sum (f) thru (i)	(e) + (j)
2	Operation										
3	Operation Supervision and Engineering	535	2,305	-	2,305	74	69	71	-	214	2,518
4	Water for Power	536	-	-	-	-	-	-	-	-	-
5	Hydraulic Expenses	537	1,633	-	1,633	52	49	50	-	151	1,784
6	Electric Expenses	538	1,021	-	1,021	33	31	31	-	95	1,116
7	Misc Hydraulic Power Expenses	539	349	-	349	11	10	11	-	32	382
8	Rents	540	-	-	-	-	-	-	-	-	-
9	Total Operation Expense		5,308	-	5,308	170	159	163	-	492	5,800
10	Maintenance										
11	Maintenance Supervision and Engineering	541	556	-	556	18	17	17	-	52	608
12	Maintenance of Structures	542	512	-	512	16	15	16	-	47	560
13	Maintenance of Reservoirs, Dams	543	679	-	679	22	20	21	-	63	742
14	Maintenance of Electric Plant	544	937	-	937	30	28	29	-	87	1,024
15	Maintenance of Misc Hydraulic Plant	545	2,275	-	2,275	73	68	70	-	211	2,485
16	Total Maintenance Expense		4,959	-	4,959	159	148	153	-	460	5,418
17	Total Hydraulic Power Generation		10,266	-	10,266	329	307	316	-	952	11,218

	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
1/ Annual Inflation Rate	3.20%	2.90%	2.90%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.20%	2.90%	2.90%

(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Other Power Generation
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.5
Witness: M. E. Guillaumin
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
Line No.	Description	Account	Projected Adjustments								Total Projected Adjustments	Projected Test Period
			1/1/22 - 12/31/22 Historical Test Period	Rate Case Adjustments 1/	Adjusted Historical Test Period	1/1/23 - 12/31/23 Inflation Adj 2/	1/1/24 - 12/31/24 Inflation Adj 2/	1/1/25 - 12/31/25 Inflation Adj 2/	Other Adjustments 3/			
1	Other Power Generation		sum (c) thru (d)							sum (f) thru (i)	(e) + (j)	
2	Operation											
3	Operation Supervision and Engineering	546	73	-	73	2	2	2	-	7	80	
4	Generation Expenses	548	4,068	-	4,068	130	122	125	(40)	337	4,405	
5	Misc Other Power Expenses	549	18,193	(16,228)	1,965	63	59	60	2,015	2,197	4,162	
6	Rents	550	-	-	-	-	-	-	-	-	-	
7	Total Operation Expense		22,334	(16,228)	6,105	195	183	188	1,975	2,541	8,646	
8	Maintenance											
9	Maintenance Supervision and Engineering	551	-	-	-	-	-	-	-	-	-	
10	Maintenance of Structures	552	-	-	-	-	-	-	223	223	223	
11	Maintenance of Generating & Electric Plant	553	32,839	(21,370)	11,469	367	343	353	2,660	3,724	15,193	
12	Maintenance of Misc Other Power Plant	554	1,541	-	1,541	49	46	47	154	297	1,839	
13	Total Maintenance Expense		34,380	(21,370)	13,010	416	389	401	3,037	4,244	17,254	
14	Power Supply Related Expenses											
15	Operation Supervision and Engineering	556	3,817	-	3,817	122	114	118	1,414	1,768	5,585	
16	Generation Expenses	557	128	(128)	-	-	-	-	-	-	-	
17	Total Expense		3,944	(128)	3,817	122	114	118	1,414	1,768	5,585	
18	Total Other Power Generation Expenses		60,658	(37,726)	22,932	734	686	706	6,426	8,553	31,485	

			1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
1/ Eliminate Renewable Energy Program		2/ Annual Inflation Rate	3.20%	2.90%	2.90%
		No. of Months in Period	12	12	12
		Pro-rated Inflation Rate	3.20%	2.90%	2.90%
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)					
1/ Rate Case Adjustments	Account	Amount	3/ Other Adjustments		
			Account		
			Amount		
Eliminate Renewable Energy Program	549, 553	(37,726)	Blue Water Operation	549, 552, 553, 554, 556	6,335
			Slocum BESS Operation	553	312
			Retired Peakers	548, 549, 552, 553, 554, 556	(221)
					6,426

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.6
Witness: A. J. Kryscynski
R. A. Bellini 1/
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Line No.	Description	Account	1/1/22 -	Eliminate	Normalization	Adjusted	Projected Adjustments				Total	Projected
			Historical				TRM	Adjustments	Historical	1/1/23 -		
			Test Period	3/	4/	Test Period	Inflation Adj	Inflation Adj	Inflation Adj	Adjustments	Adjustments	Test Period
							5/	5/	5/	6/		
						sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
1	Distribution Expenses											
2	Miscellaneous Transmission Expenses	566	7,431	(7,431)	-	-	-	-	-	-	-	-
3	Operation Supervision and Engineering	580	59,923	-	-	59,923	1,918	1,793	1,845	1,600	7,156	67,080
4	Load Dispatching	581	2,025	-	-	2,025	65	61	62	-	188	2,213
5	Station Expenses	582	5,195	-	-	5,195	166	155	160	-	482	5,676
6	Overhead Line Expenses	583	8,232	-	-	8,232	263	246	253	-	763	8,995
7	Underground Line Expenses	584	1,427	-	-	1,427	46	43	44	-	132	1,559
8	Street Lighting and Signal System Exp	1/ 585	-	-	-	-	-	-	-	-	-	-
9	Meter Expenses	586	8,299	-	-	8,299	266	248	256	-	769	9,068
10	Customer Installations Expenses	587	421	-	-	421	13	13	13	-	39	460
11	Miscellaneous Expenses	588	35,769	(7,292)	-	28,477	911	852	877	300	2,940	31,417
12	Amortization of Deferred ADMS Costs	588	0	-	-	0	-	-	-	1,186	1,186	1,186
13	Rents	589	-	-	-	-	-	-	-	-	-	-
14	Total Operation Expense		128,721	(14,723)	-	113,998	3,648	3,412	3,511	3,086	13,657	127,655
15	Maintenance											
16	Maintenance Supervision and Engineering	590	2,286	-	-	2,286	73	68	70	-	212	2,498
17	Maintenance of Structures	591	1,970	-	-	1,970	63	59	61	-	183	2,153
18	Maintenance of Station Equipment	592	17,014	-	-	17,014	544	509	524	-	1,578	18,592
19	Maintenance of Overhead Lines-Tree Trim	2/ 593	105,626	-	-	105,626	-	-	-	3,374	3,374	109,000
20	Maintenance of Overhead Lines-Other	593	78,299	-	(2,614)	75,685	2,422	2,265	2,331	(3,800)	3,218	78,903
21	Maintenance of Underground Lines	594	14,936	-	-	14,936	478	447	460	-	1,385	16,321
22	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-	-	-
23	Maintenance of Street Lighting and Signal Systems	1/ 596	3,991	-	(250)	3,741	120	112	115	-	347	4,088
24	Maintenance of Meters	597	-	-	-	-	-	-	-	-	-	-
25	Maintenance of Misc Distribution Plant	598	-	-	-	-	-	-	-	-	-	-
26	Total Maintenance Expense		224,123	-	(2,864)	221,259	3,700	3,461	3,561	(426)	10,296	231,555
27	Total Distribution Expenses		352,844	(14,723)	(2,864)	335,257	7,348	6,872	7,072	2,660	23,952	359,210

Other Sponsoring Witnesses

1/ Street Lighting and Signal Systems (accounts 585 and 596) are sponsored by Witness Bellini
2/ Tree Trim Expenses (account 593) are sponsored by Witness Steudle (Exh. A-13 C5.6.1)

Historical Adjustments

3/ Eliminate expenses recovered through Transitional Reconciliation Mechanism (TRM)

4/ Normalization Adjustments:	Account	Amount
Restoration (Exh. A-13 C5.6 p.2, Line 18, col. (j))	593	(2,614)
Reduced Outage Expenses		(250)
Total Normalization Adjustments		(2,864)

Projection Adjustments

	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
5/ Inflation Adjustment:			
Annual Rate	3.20%	2.90%	2.90%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.20%	2.90%	2.90%
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)			

6/ Other Projected Adjustments:	Account	Amount
Tree Trim	593	3,374
ADMS Regulatory Asset Amortization sponsored by Witness Uzenski Exh. A-13 C5.6.2, Line 11, Col. (h)	588	1,186
Surge tree trim savings sponsored by Witness Steudle Exh. A-22, Schedule L1, p.1 Line 9 & 10, Col. (g) minus Line 9 & 10 Col. (h)	593	(8,800)
Peaker Study	588	300
Damage Prevention Program	583	1,600
DO Inspection Costs Previously Capitalized	593	5,000
Total Projection Adjustments		2,660

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Restoration Expenses
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.6
Witness: A. J. Kryscynski
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	5 Yr Avg	1/1/25 - 12/31/25 Projected Test Period	1/1/22 - 12/31/22 Historical Test Period	Restoration Adjustment
								1/		(h) - (i)
1	Storm Restoration									
2	Actual O&M Reported	48,182	47,213	39,657	73,429	60,850	53,866			
3	Inflation Adjustment	7,947	6,814	5,186	5,874	-	5,164			
4	Inflation Adjusted Historical O&M	56,129	54,027	44,843	79,303	60,850	59,030	59,030	60,850	(1,820)
5	Inflation 1/1/23 -12/31/23 3.20%							1,889	1,947	(58)
6	Inflation 1/1/24 -12/31/24 2.90%							1,767	1,821	(54)
7	Inflation 1/1/25 -12/31/25 2.90%							1,818	1,874	(56)
8	Projected Storm Restoration							64,504	66,492	(1,988)
9	Non-Storm Restoration									
10	Actual O&M Reported	55,956	55,443	46,335	47,657	59,116	52,901			
11	Inflation Adjustment	9,229	8,002	6,059	3,813	-	5,420			
12	Inflation Adjusted Historical O&M	65,184	63,445	52,394	51,470	59,116	58,322	58,322	59,116	(794)
13	Inflation 1/1/23 -12/31/23 3.20%							1,866	1,892	(25)
14	Inflation 1/1/24 -12/31/24 2.90%							1,745	1,769	(24)
15	Inflation 1/1/25 -12/31/25 2.90%							1,796	1,821	(24)
16	Projected Non-Storm Restoration							63,730	64,597	(868)
17	Total Restoration Expense									
18	Total Restoration Normalization Adjustment (Line 4 + Line 12)							117,352	119,966	(2,614) 2/
19	Inflation 1/1/23 -12/31/23 3.20%							3,755	3,839	(84)
20	Inflation 1/1/24 -12/31/24 2.90%							3,512	3,590	(78)
21	Inflation 1/1/25 -12/31/25 2.90%							3,614	3,694	(80)
22	Total Projected Restoration Expense (Line 8 + Line 16)							128,233	131,090	(2,856)

1/ Five year average of actual expense adjusted for inflation is included in this request.

2/ Historical normalization adjustment carried to Account 593 (see Exhibit A-13 C5.6 page 1 line 20).

Michigan Public Service Commission
DTE Electric Company
Projected Tree Trim Expenses
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.6.1
Witness: R. Steudle
Page: 1 of 1

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	<u>Tree Trim Regulatory Deferral</u>	2019-A	2020-A	2021-A	2022-A	2023	2024	2025	2026	Total
2	Approved Tree Trim - Surge Funding	43,300	74,100	70,500	58,200	67,000	52,700	43,700	-	409,500
3	Additional Funding Request	-	-	-	-	-	-	87,000	-	87,000
4	Total Tree Trim Regulatory Deferral	<u>43,300</u>	<u>74,100</u>	<u>70,500</u>	<u>58,200</u>	<u>67,000</u>	<u>52,700</u>	<u>130,700</u>	<u>-</u>	<u>496,500</u>

Carried to Exhibit A-11 A1.1

5 **Tree Trim O&M - Base Level**

6	U-21534 Test Period Request:	Annual Amount
7	Test Year 12 Months Ending 12/31/25	109,000
8	Historical 2022	<u>105,626</u>
9	Projection Adjustment	<u>3,374</u>

Exhibit A-13, Schedule C5.6, page 1, Line 19, Column (f)

Carried to Exhibit A-13, Schedule C5.6, line 19

Michigan Public Service Commission
DTE Electric Company
Advanced Distribution Management System (ADMS)
Regulatory Asset Amortization
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.6.2
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line No.	Description	Actual May-Dec 2019	Actual CY 2020	Actual CY 2021	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025	Total Deferral	Reference
1	ADMS Deferral (Note 1)									
2	Energy & Generation Mgmt Systems	780	-	-	-	-	-	-	780	
3	Network Management System	809	655	-	-	-	-	-	1,464	
4	Outage Management System	938	2,501	1,996	3,669	1,039	-	-	10,142	
5	Distribution Management System	313	834	697	1,010	2,555	-	-	5,409	
6	Total Regulatory Asset Deferral	2,840	3,989	2,693	4,678	3,594	-	-	17,795	Sponsored by Witness Elliott-Andahazy (Exh.A-12, B5.4 page 2)

		Amortization Expense						
Line No.	Description	Deferral by Component	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025	Test Period Amortization	In Service
								Amortization Period
7	ADMS Amortization (Note 2)							
8	Energy & Generation Mgmt Systems	780	52	52	52	52	52	2019
9	Network Management System	1,464	98	98	98	98	98	2020
10	Outage Management System	10,142	-	-	676	676	676	2023
11	Distribution Management System	5,409	-	-	361	361	361	2023
12	Total Amortization Expense		150	150	1,186	1,186	1,186	

1/ Authorization to defer ADMS costs incurred after May 2019 to a regulatory asset per order in Case No. U-20162

2/ Deferred costs are amortized over a 15-year period in the subsequent year of in-service

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Customer Service
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.7
Witness: M.J. Hatsios
Page: 1 of 1

Line No.	(a) Description	(b) Account	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
			Rate Case Adjustments				Projected Adjustments					Total Projected Adjustments	Projected Test Period
			1/1/22 - 12/31/22 Historical Test Period	Eliminate Energy Waste Reduction Program	Eliminate LIEAF	Other Adjustments	Adjusted Historical Test Period	1/1/23 - 12/31/23 Inflation 2/	1/1/24 - 12/31/24 Inflation 2/	1/1/25 - 12/31/25 Inflation 2/	Other Adjustments		
1	Customer Accounts Expenses						sum (c) thru (f)					sum (h) thru (k)	(g) + (l)
2	Operation												
3	Supervision	901	2,048	-	-	-	2,048	66	61	63	-	190	2,238
4	Meter Reading Expenses	902	2,051	-	-	-	2,051	66	61	63	-	190	2,241
5	Customer Records and Collection Expenses	903	76,882	-	-	-	76,882	2,460	2,301	2,368	(6,399) 3/	730	77,611
6	Customer Collection-Merchant Fees	903	11,783	-	-	-	11,783				513 4/	513	12,296
7	Customer 360 Reg Asset Amortization	903	2,797	-	-	-	2,797				-	-	2,797 5/
8	ACPP/Time of Day Reg Asset Amortization	903	110	-	-	-	110				3,013 6/	3,013	3,123
9	Miscellaneous Customer Accounts Expenses	905	80,900	(80,900)	-	-	0	0	0	0	-	0	0
10	Total Operation Expense		176,570	(80,900)	-	-	95,670	2,591	2,424	2,494	(2,873)	4,636	100,306
11	Customer Service and Informational Expenses												
12	Operation												
13	Supervision	907	4,904	(1,111)	-	-	3,793	121	114	117	-	352	4,144
14	Customer Assistance Expenses	908	124,835	(85,931)	(23,895)	-	15,009	480	449	462	-	1,392	16,401
15	Informational and Instructional Expenses	909	5,036	(5,039)	-	-	(3)	(0)	(0)	(0)	-	(0)	(3)
16	Miscellaneous Customer Service and	910	5,605	-	-	-	5,605	179	168	173	-	520	6,125
17	Informational Expenses						-				-		
18	Total Operation Expense		140,380	(92,081)	(23,895)	-	24,404	781	730	752	-	2,263	26,667
19	Total Customer Service Accounts		316,950	(172,981)	(23,895)	-	120,075	3,372	3,154	3,245	(2,873)	6,898	126,973
20	Less Reclass to Marketing Exhibit 1/	907-908	7,640	-	-	-	7,640	244	229	235	-	708	8,348
21	Total Customer Service excluding Marketing		309,310	(172,981)	(23,895)	-	112,435	3,128	2,925	3,010	(2,873)	6,190	118,625

1/ Reclassify marketing expenses to Exhibit A-13 C5.9 line 5, sponsored by Witness Bennett

3/ Customer Records and Collection Expenses	Account	Amount
Digital Investment - Call Volume Reduction	903	(6,399)

	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
2/ Annual Inflation Rate	3.20%	2.90%	2.90%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.20%	2.90%	2.90%

(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)

4/ Merchant Fees projection adjustment is sponsored by Witness Bennett (Exh. A-13 C5.7.1)

5 / Customer 360 regulatory asset amortization sponsored by Witness Uzenski

6/ Advanced Customer Pricing Pilot/Time of Day reg asset amort (sponsored by Witness Uzenski Exh. A-13 C5.9.3)

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Customer Service - Credit/Debit Card Merchant Fees
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.7.1
Witness: P. Bennett
Page: 1 of 2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
				1/1/22 - 12/31/22				
Line No.	Description	Account	Historical Test Period	Historical Adjustment	Adjusted Historical Test Period	Other Adjustments	Projected Test Period	
1	Customer Accounts Expenses				(c) + (d)		(e) + (f)	
2	Operation							
3	Customer Collection-Merchant Fees Residential	903	7,541	-	7,541	1,280	8,822	
4	Customer Collection-Merchant Fees Non-Residential	903	4,242	-	4,242	(767)	3,474	
5	Total Customer Collection-Merchant Fees 1/	903	11,783	-	11,783	513	12,296	

1/ Carried to Exhibit A-13 C5.7 line 6, sponsored by Witness Sparks

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Customer Service - Credit/Debit Card Merchant Fees
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.7.1
Witness: P. Bennett
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Historic Actuals				2 year Growth	Forecast			Projected Test Period
		2019	2020	2021	2022		2023	2024	2025	
1	Merchant Fees									
2	Merchant Fees Residential	\$ 6,992	\$ 9,437	\$ 9,977	\$ 7,541	0.5%	\$ 8,734	\$ 8,778	\$ 8,822	8,822
3	Merchant Fees Non-Residential	5,427	4,240	3,880	4,242	0.5%	3,440	\$ 3,457	\$ 3,474	3,474
4	Total Merchant Fees	<u>\$ 12,418</u>	<u>\$ 13,677</u>	<u>\$ 13,857</u>	<u>\$ 11,783</u>		<u>\$ 12,174</u>	<u>\$ 12,235</u>	<u>\$ 12,296</u>	<u>\$ 12,296</u>

Assumptions:

- 1) 2023 forecast is derived from the September YTD actuals, and three months of forecast
- 2) The 2 year growth rate that is expected from 2023 to 2025 electric customer count was applied to the 2023 value to develop the 2024 and 2025 forecast.
- 3) The 2 year growth from 2023 to 2025 is based on Projected Average Number of Customers in exhibit A-15, E6, Pg1 line 6, 7 and 8.

DTE Electric Company
Projected Operation and Maintenance Expenses
Customer Service - Uncollectible Expense
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.8
Witness: J. Sparks
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	Account	1/1/22 - 12/31/22 Historical Test Period	Historical Adjustment	Adjusted Historical Test Period	Projected Adjustments 1/	Projected Test Period
	Uncollectible Expense				(c) + (d)		(e) + (f)
1	Uncollectible Accounts	904	35,199	-	35,199	15,671	50,870
	Description	2022	2021	2020			
2	Accounts Written-Off	\$ 65,303	\$ 76,776	\$ 79,896			
3	(less) Collection of Accounts Written-Off	\$ (27,645)	\$ (36,732)	\$ (30,170)			
4	Net Write-Offs	\$ 37,658	\$ 40,044	\$ 49,726			
5	Billed Revenue	\$ 5,614,043	\$ 5,551,588	\$ 5,286,147			
6	Net Write-Offs to Revenue Percentage	0.6708%	0.7213%	0.9407%			
7	Charges to Direct Expense	\$ 2,744	\$ (146)	\$ 2,780			
	Projected Billed Revenue						
8	12 month's ending 12/31/25			\$ 6,311,489			
9	3-Year Average Net Write-Offs to Revenue			0.78%			
10	Projected Net Write-Offs (ln 8 x ln 9)			\$ 49,078			
	Historical 3 Year Average Charges to Direct						
11	Expense (ln 7)			\$ 1,793			
	Projected Uncollectible Accounts Expense (ln						
12	10+ ln 11)			\$ 50,870			
	Reconcile Historical to Projected						
13	Historical 2022			35,199			
14	Projection Adjustment 1/			15,671			
15	Adjusted Projected			50,870			

1/ Adjust to 3 year historical average of net-write-offs as a % of revenue plus direct expense

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Regulated Marketing
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.9
Witness: P. Bennett
Page: 1 of 1

Line No.	(a) Description	(b) Account	(c) 1/1/22 - 12/31/22 Historical Test Period	(d) Rate Case Adjustments	(e) Adjusted Historical Test Period	(f) (g) (h) (i) Projected Adjustments				(j) Total Projected Adjustments	(k) Projected Test Period
						1/1/23 - 12/31/23 Inflation 3/	1/1/24 - 12/31/24 Inflation 3/	1/1/25 - 12/31/25 Inflation 3/	Other Adjustments 4/		
1	Customer Service and Informational Expenses				sum (c) thru (d)					sum (f) thru (i)	(e) + (j)
2	Operation										
3	Supervision	907	713	-	713	23	21	22	-	66	779
4	Customer Assistance Expenses	908	6,927	-	6,927	222	207	213	-	642	7,569
5	Total Customer Service (Major Account Services)		7,640	-	7,640	244	229	235	-	708	8,348
6	Sales Expenses										
7	Operation										
8	Supervision	911	1,891	-	1,891	61	57	58	-	175	2,066
9	Demonstrating and Selling Expenses-DR 1/	912	2,701	-	2,701	86	81	83	2,961	3,211	5,913
10	Demonstrating and Selling Expenses-Other	912	8,178	-	8,178	262	245	252	3,252	4,011	12,189
11	Miscellaneous Sales-Charging Forward Amort	912	126	-	126	-	-	-	3,512	3,512	3,638
12	Advertising Expenses	913	-	-	-	-	-	-	-	-	-
13	Miscellaneous Sales-Other	916	-	-	-	-	-	-	-	-	-
14	Total Sales Expenses		12,897	-	12,897	409	382	393	9,725	10,909	23,806
15	Total Marketing Expense		20,536	-	20,536	653	611	629	9,725	11,618	32,154

1/ Demand Response is sponsored by Witness Farrell

	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
3/ Annual Inflation Rate	3.20%	2.90%	2.90%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.20%	2.90%	2.90%
(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)			

4/ Projection Adjustments:	Account	Amount
Smart Savers (sponsored by Witness Farrell)	912	1,724
SmartCurrents (sponsored by Witness Farrell)	912	(496)
SmartCharge (sponsored by Witness Farrell)	912	767
Pilots and other projects (sponsored by Witness Farrell)	912	966
Subtotal Demand Response		2,961
Charging Forward Expansion (Sponsored by Witness Bennett Exh. A-12 B5.9)	912	3,252
Charging Forward Reg Asset Amort (sponsored by Witness Uzenski Exh. A-13 C5.9.1)	912	3,512
		9,725

Michigan Public Service Commission
DTE Electric Company
Charging Forward Regulatory Asset Amortization
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.9.1
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025		Reference
1	Charging Forward Regulatory Asset Expenses						
2	Charging Forward Deferral (Note 3)	5,985	6,927	15,922	20,128		Sponsored by Witness P. Bennett (Exh.A-12, B5.9)
3	Total Regulatory Asset Deferral	5,985	6,927	15,922	20,128		

		Amortization Expense					Case No.		Amortization Period	
	Deferral by Vintage Year	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025	Test Period Amortization			Beginning	Ending
4	Charging Forward Amortization									
5	2019 Vintage (Jan-Sep)	44	44	44	18	18	U-20561		6/1/2020	5/31/2025
6	2019 Vintage (Oct-Dec)	14	162	162	162	162	U-20836		12/1/2022	11/30/2027
7	2020 Vintage	23	280	280	280	280	U-20836		12/1/2022	11/30/2027
8	2021 Vintage	50	595	595	595	595	U-20836		12/1/2022	11/30/2027
9	2022 Vintage	-	100	1,197	1,197	1,197	U-21297		12/1/2023	11/30/2028
10	2023 Vintage (Projected)	-	-	-	1,385	1,385	U-21534		1/1/2025	12/31/2029
11	Total Amortization Expense	130	1,181	2,279	3,638	3,638				

- 1/ Authorization to defer Charging Forward Phase I costs to a regulatory asset per order in Case No. U-20162
2/ Authorization to defer Charging Forward Phase II eFleets Costs to a regulatory asset per order in Case No. U-20935
3/ Authorization to defer Charging Forward Expansion costs to a regulatory asset per order in Case Nos. U-20836 & U-21297
4/ Deferred costs amortized over a five-year period upon inclusion in base rates

Michigan Public Service Commission
DTE Electric Company
Advanced Customer Pricing Pilot (ACPP) & Time of Day (TOD)
Regulatory Asset Deferral
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.9.2
Witnesses: M. Hatsios
P. Bennett
Page: 1 of 1

Line No.	(a) Description	(b) Actual CY 2019	(c) Actual CY 2020	(d) Actual CY 2021	(e) Actual CY 2022	(f) Projected CY 2023	(g) Projected CY 2024	(h) Projected CY 2025	(i) Total	(j) Sponsoring Witness
1	Advanced Customer Pricing Pilot Deferral (Note 1)									
2	Information Technology	58	862	1,302	321	-	-	-	2,542	M. Hatsios
3	Customer Outreach	107	1,512	1,347	-	-	-	-	2,966	P. Bennett
4	Customer Service	-	-	-	-	-	-	-	-	M. Hatsios
5	Evaluation, Monitoring, & Verification and Operational Support	-	283	171	172	-	-	-	626	P. Bennett
6	Insight	-	358	100	6	-	-	-	464	M. Hatsios
7	Total ACPP Deferral	<u>165</u>	<u>3,015</u>	<u>2,920</u>	<u>499</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>6,599</u>	

1/ Authorization to defer ACPP project costs to regulatory asset per order in Case No. U-20602

		Actual CY 2019	Actual CY 2020	Actual CY 2021	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025	Total	Sponsoring Witness
8	Time of Day Implementation Project Costs Deferral (Note 2)									
9	Information Technology	-	-	-	1,601	881	-	-	2,482	M. Hatsios
10	Customer Outreach	-	-	-	2,044	453	-	-	2,497	P. Bennett
11	Customer Service	-	-	-	-	5,152	-	-	5,152	M. Hatsios
12	Subtotal TOD Expense	-	-	-	3,644	6,486	-	-	10,130	
13	Less TOD Expense thru November 18, 2022	-	-	-	(1,665)	-	-	-	(1,665)	
14	Total TOD Deferral	<u>-</u>	<u>-</u>	<u>-</u>	<u>1,979</u>	<u>6,486</u>	<u>-</u>	<u>-</u>	<u>8,465</u>	

2/ Authorization to defer TOD project costs to regulatory asset per order in Case No. U-20836 (effective November 2022)

Michigan Public Service Commission
DTE Electric Company
Advanced Customer Pricing Pilot (ACPP) & Time of Day (TOD)
Regulatory Asset Amortization
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.9.3
Witnesses: T.M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line No.	Description	Actual CY 2019	Actual CY 2020	Actual CY 2021	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025	Total	Reference
1	<u>Regulatory Asset Deferral</u>									
2	Advanced Customer Pricing Pilot	165	3,015	2,920	499	-	-	-	6,599	Exh. A-13, Sch. C5.9.2, Line 7
3	Time of Day Implementation	-	-	-	1,979	6,486	-	-	8,465	Exh. A-13, Sch. C5.9.2, Line 14
	Total Regulatory Asset Deferral	165	3,015	2,920	2,478	6,486	-	-	15,064	

Amortization Expense						Case No.	Amortization Period	
	Deferral	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025		Beginning	Ending
3								
4								
5	Regulatory Asset Amortization (Note 1)							
6	Advanced Customer Pricing Pilot 1/	6,599	110	1,320	1,320	1,320	U-20836	12/1/2022 11/30/2027
7	Time of Day Implementation 2/	8,465	-	141	1,693	1,693	U-21297	12/1/2023 11/30/2028
8	Total Amortization Expense		110	1,461	3,013	3,013		

1/ Deferred ACPP costs (authorized in Case No. U-20162) are amortized over a five-year period effective with inclusion in base rates in Case No. U-20836.

2/ Deferred TOD costs (authorized in Case No. U-20836) are amortized over a five-year period effective with inclusion in base rates in Case No. U-21297.

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Administrative and General Expenses
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.10
Witness: T. M. Uzenski
Page: 1 of 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
							Projected Adjustments					
			1/1/22 - 12/31/22	Rate Case	Normalization	Adjusted	1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25		Total	
Line	Description	Account	Historical	Adj.	Adj.	Historical	Inflation	Inflation	Inflation	Other	Projected	Projected
No.			Test Period	1/	2/	Test Period	3/	3/	3/	4/	Adjustments	Test Period
1	Administrative and General Expenses					sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
2	Operation											
3	Administrative and General Salaries	920	135,350	(16,676)	(3,931)	114,742	3,672	3,434	3,534	-	10,639	125,382
4	Office Supplies and Expenses	921	60,193	(3,032)	-	57,161	1,829	1,711	1,760	-	5,300	62,461
5	(Less) Administrative Expenses Transferred-Cr.	922	(64,260)	-	-	(64,260)	(2,056)	(1,923)	(1,979)	-	(5,958)	(70,218)
6	Outside Services Employed	923	33,237	(669)	(5,300)	27,268	873	816	840	-	2,528	29,797
7	Property Insurance	924	4,345	(1,566)	-	2,779	89	83	86	-	258	3,036
8	Injuries and Damages	925	17,158	-	1,282	18,440	-	-	-	-	-	18,440
9	Franchise Requirements	927	-	-	-	-	-	-	-	-	-	-
10	Regulatory Commission Expenses	928	1	-	-	1	0	0	0	-	0	1
11	(Less) Duplicate Charges-Cr.	929	-	-	-	-	-	-	-	-	-	-
12	General Advertising Expenses	930.1	10,965	(5,714)	-	5,251	168	157	162	-	487	5,738
13	Miscellaneous General Expenses	930.2	7,927	(255)	(2,720)	4,952	158	148	152	-	459	5,411
14	Environmental Remediation	930.2	4,568	-	(11)	4,557	-	-	-	-	-	4,557
15	Rents	931	8,124	(1,251)	-	6,873	220	206	212	-	637	7,510
16	Total Operation Expense		217,607	(29,163)	(10,680)	177,764	4,953	4,632	4,766	-	14,351	192,114
17	Maintenance											
18	Maintenance of General Plant	935	5,608	-	-	5,608	179	168	173	-	520	6,128
19	Total Maintenance Expense		5,608	-	-	5,608	179	168	173	-	520	6,128
20	Grand Total Operation & Maintenance Expense		223,216	(29,163)	(10,680)	183,372	5,132	4,800	4,939	-	14,871	198,243

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Administrative and General Expenses
(\$000)

Case No.: U-21534
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	Account	Historical Adjustment			1/1/23 - 12/31/23	1/1/24 - 12/31/24	1/1/25 - 12/31/25
1/ Rate Case Adjustments:				3/ Annual Inflation Rate	3.20%	2.90%	2.90%
Eliminate Top 5 Executives Incentive Compensation	920	(10,157)	Exh. A-3 C19	No. of Months in Period	12	12	12
Eliminate Renewable Energy Program	920	(6,205)	WP TMU-15	Pro-rated Inflation Rate	3.20%	2.90%	2.90%
Regional Relations Expenses Political Advocacy	920	(314)					
Eliminate Renewable Energy Program	924	(1,566)	WP TMU-15	(carried from Exh. A-13 C5.7, Sch.C5.15)			
Eliminate Renewable Energy Program	921	(3,032)	WP TMU-15				
Eliminate Renewable Energy Program	923	(370)	WP TMU-15				
Relcass to Other Deductions - below the line	923	(299)					
Eliminate Renewable Energy Program	931	(288)	WP TMU-15				
Disallowed Advertising Expenses	930.1	(5,714)	Exh. A-3 C15				
Disallowed Corporate Memberships	930.2	(255)	Exh. A-3 C14				
Eliminate MGM Rent Expense	931	(963)	WP TMU-4				
Total Rate Case Adjustments		(29,163)		4/ Other Projected Adjustments:			
2/ Normalization Adjustments:							
Employee Incentive Plan Adjustment	920	(4,787)	Exh. A-3 C20				
Incentive Compensation deferral above base	920	856	Exh A-13 C5.10.1				
One time consulting costs	923	(5,300)					
One time consulting costs	930.2	(2,720)					
Injuries & Damages - five year historical average	925	1,282	Exh. A-13, Sch. C5.10, page 3				
Environmental Remediation - five year historical avg	930.2	(11)	Exh. A-13, Sch. C5.10, page 3				
Total Normalization Adjustments		(10,680)					

Account	Amount

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Administrative and General Expenses
(\$000)

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line	Description	Account	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Average	Normalization Adjustment
No.									col. (h) - (g)
1	Injuries & Damages Expense	925	19,344	11,042	11,702	32,953	17,158	18,440	1,282
2	Environmental Remediation	930.2	4,005	2,411	6,751	5,051	4,568	4,557	(11)

Michigan Public Service Commission
DTE Electric Company
Incentive Deferral Mechanism
Administrative and General Expenses
(\$000)

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	Actual 2022	Projected 2023	Projected 2024	Projected 2025	Projected Test Period	Reference
1	Incentives Deferral						
2	Incentives related to operational metrics	1,917	5,987	19,918			January 2025 forward = reset base to actuals
3	Base Incentives 1/	1,061	12,735	10,142			Base \$12.7M / 12 * 1 months = \$1.1M in column (b)
4	Amount Deferred to Regulatory Asset/(Liability)	856	(6,748)	9,776			Line 2 - Line 3

1/ Per Case No. U-21297, the Commission allows recovery of 52% of O&M incentive compensation related to operational measures. Also authorizes DTE Electric to continue its use of a two-way tracker mechanism which requires refunds to customers if 52% target level is not achieved or allow the Company to recover additional funds if it exceeds the 52% target level, up to a maximum of 100% target level. Incentives within base rates were reduced from \$12.735 million to \$10.142 million as a result of the order in Case No. U-21297.

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Employee Pensions and Benefits
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C5.11
 Witness: J. K. Hooper
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Line No.	Description	(a)	(b)	(c)	(d)
		Employee Pensions and Benefits Expense			
		Historical Period Ending 12/31/22	Adjustments	Projected Period Ending 12/31/25	
1	<u>Post-Employment Benefits</u>				
2	Pension	12,247	(12,247)	-	
3	Post Empl Health Care (OPEB)	-	(18,300)	(18,300)	
4	New Hire VEBA	6,680	3,167	9,847	
5	Employee Savings Plan	29,699	7,706	37,406	
6	Subtotal Post-Employment Benefits	48,627	(19,674)	28,953	
7	<u>Active Healthcare</u>				
8	Medical Expenses	46,676	5,548	52,224	
9	Dental Expenses	3,193	379	3,572	
10	Vision Expenses	256	30	286	
11	Subtotal Active Healthcare	50,126	5,957	56,083	
12	<u>Other</u>				
13	Accrued Vacation Expense	(5,439)	4,896	(543)	
14	Supplemental Severance Plan Expense	734	(624)	110	
15	Supplemental Savings Plan	(3,599)	6,806	3,207	
16	Deferred Compensation Plan	(85)	180	95	
17	Wellness Plan Expenses	4,995	565	5,560	
18	Life Insurance	252	23	276	
19	Long-Term Disability Expenses	1,354	126	1,480	
20	Affordable Care Act	19	3	22	
21	General Benefit Expenses	2,198	197	2,395	
22	Benefit Plan Admin Fees	6,697	599	7,296	
23	Retirement Administration Fees	325	29	354	
24	Medical Refund Amortization	(578)	578	-	
25	O&M Project Reimbursements	(1,558)	(139)	(1,698)	
26	Subtotal Other	5,318	13,237	18,554	
27	Total before Other Allocations	104,071	(481)	103,590	
28	A&G Capitalization	(13,204)	(1,181)	(14,384)	
29	Other Transfers & Allocations	(928)	(83)	(1,011)	
30	Eliminate Surcharge Programs	-	(3,936)	(3,936)	
31	Total Benefit Expense (Account 926)	89,939	(5,680)	84,259	

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Employee Pension and Benefits (\$000)
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Historical Period Ending 12/31/22	Normalization Adjustments	Adjusted Historical Test Period Col (b) + Col (c)	Projected Adjustments			Other Adjustments	Total Projected Adjustments Sum (e) thru (h)	Projected Period Ending 12/31/25 Col (d) + Col (i)
					1/1/23 - 12/31/23 Inflation 1/	1/1/24 - 12/31/24 Inflation 1/	1/1/25 - 12/31/25 Inflation 1/			
1	Post-Employment Benefits									
2	Pension 12/	12,247	(12,247) 2/	-	-	-	-	-	-	-
3	Post Empl Health Care (OPEB)	-	-	-	-	-	-	(18,300)	(18,300)	(18,300) 3/
4	New Hire VEBA	6,680	1,027 4/	7,707	-	-	-	2,140	2,140	9,847
5	Employee Savings Plan 12/	29,699	378 5/	30,077	-	-	-	7,328	7,328	37,406
6	Subtotal Post-Employment Benefits	48,627	(10,843)	37,784	-	-	-	(8,832)	(8,832)	28,953
7	Active Healthcare									
8	Medical Expenses	46,676	(1,173) 6/	45,504	2,321	2,391	2,009	-	6,721	52,224
9	Dental Expenses	3,193	(81) 6/	3,113	159	164	137	-	460	3,572
10	Vision Expenses	256	(7) 6/	249	13	13	11	-	37	286
11	Subtotal Active Healthcare	50,126	(1,260)	48,866	2,492	2,568	2,157	-	7,217	56,083
12	Other									
13	Accrued Vacation Expense	(5,439)	4,942 7/	(497)	(15)	(15)	(16)	-	(46)	(543)
14	Supplemental Severance Plan Expense 12/	734	-	734	-	-	-	(624)	(624)	110
15	Supplemental Savings Plan 12/	(3,599)	6,055 8/	2,456	-	-	-	751	751	3,207
16	Deferred Compensation Plan 12/	(85)	173 8/	88	-	-	-	7	7	95
17	Wellness Plan Expenses	4,995	-	4,995	255	263	221	(173)	565	5,560
18	Life Insurance	252	-	252	8	8	8	-	23	276
19	Long-Term Disability Expenses	1,354	-	1,354	41	42	43	-	126	1,480
20	Affordable Care Act	19	-	19	1	1	1	-	3	22
21	General Benefit Expenses	2,198	-	2,198	90	55	52	-	197	2,395
22	Benefit Plan Admin Fees	6,697	-	6,697	275	167	157	-	599	7,296
23	Retirement Administration Fees 12/	325	-	325	13	8	8	-	29	354
24	Medical Refund Amortization	(578)	-	(578)	-	-	-	578	578	- 9/
25	O&M Project Reimbursements	(1,558)	-	(1,558)	(64)	(39)	(37)	-	(139)	(1,698) 10/
26	Subtotal Other	5,318	11,170	16,487	603	489	436	538	2,067	18,554
27	Total before Other Allocations	104,071	(933)	103,137	3,095	3,057	2,593	(8,293)	453	103,590
28	A&G Capitalization	(13,204)	-	(13,204)	(541)	(330)	(310)	-	(1,181)	(14,384)
29	Other Transfers & Allocations	(928)	-	(928)	(38)	(23)	(22)	-	(83)	(1,011)
30	Eliminate Surcharge Programs	-	(3,936) 11/	(3,936)	-	-	-	-	-	(3,936)
31	Total Benefit Expense (Account 926)	89,939	(4,869)	85,070	2,516	2,704	2,262	(8,293)	(811)	84,259

1/ Inflation Adjustment Factors: see table below

2/ Deferral of pension expense per Order in Case No.U- 21297

3/ Carried from Line 21 of Exhibit A-13, Schedule C5.12.2

4/ Adjust 2021 True-Up adjustment to five year average

5/ Adjust Forfeitures to five year average

6/ Constant Dollar Active Healthcare Adjustment (A-13, C5.11.3)

7/ Normalization adjustment to reflect five year average

8/ Normalize return on assets to 6.80%

9/ Medical Refund regulatory liability of \$5.2M amortized over 3 years May 1, 2019 - April 30, 2022 (sponsored by Witness Uzenski)

10/ Related to Belle River Power Plant chargeout agreement (sponsored by Witness Uzenski)

11/ Eliminate benefits expense included in separate surcharge mechanisms (sponsored by Witness Uzenski)

12/ Sponsored by Witness Fix

Annual Inflation Rates applied to benefits:		Annual 2023	Annual 2024	Annual 2025		Annual 2023	Annual 2024	Annual 2025
	Medical Expenses	5.10%	5.00%	4.00%	Wellness Plan Expenses	5.10%	5.00%	4.00%
	Dental Expenses	5.10%	5.00%	4.00%	Disability Expenses	3.00%	3.00%	3.00%
	Vision Expenses	5.10%	5.00%	4.00%	General Benefit Expenses	4.10%	2.40%	2.20%
	Life Insurance	3.00%	3.00%	3.00%	Retirement Administration Fees	4.10%	2.40%	2.20%
	Benefit Plan Admin Fees	4.10%	2.40%	2.20%	O&M Project Reimbursements	4.10%	2.40%	2.20%
	Accrued Vacation Expense	3.00%	3.00%	3.00%	A&G Capitalization	4.10%	2.40%	2.20%
					Other Transfers & Allocations	4.10%	2.40%	2.20%

Trend Considerations for 2024 Plan Year

(Active/Pre-Medicare Self-Funded Plans)

DTE Energy

November 2023

Disclaimer and Limitations on Use

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Exhibit No.: A-13
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Executive Summary

- WTW recommends a composite 2023 to 2024 trend assumption of **7.1%** for medical and prescription drug claim costs
 - Trend recommendation is given for plan trend, which includes allowed trend plus trend leveraging on fixed-level cost sharing provisions
 - Plan trend is appropriate for underwriting, cost forecasting and reserve development
 - This recommendation applies to active and pre-65 medical and pharmacy self-funded claims
 - The current trend recommendation is 0.6% higher than last year's trend recommendation
 - Increase in trend assumption is driven primarily by external economic factors (general inflation)

Component	2022 Plan Trend	2023 Plan Trend	% of Claim Cost ¹
Medical	5.5%	6.5%	75%
Prescription Drugs	9.5%	9.0%	25%
Composite	6.5%	7.1%	100%

1. Average claim distribution for DTE Energy based on DTE's experience for calendar year 2022.

Methodology for Trend Assumption Development

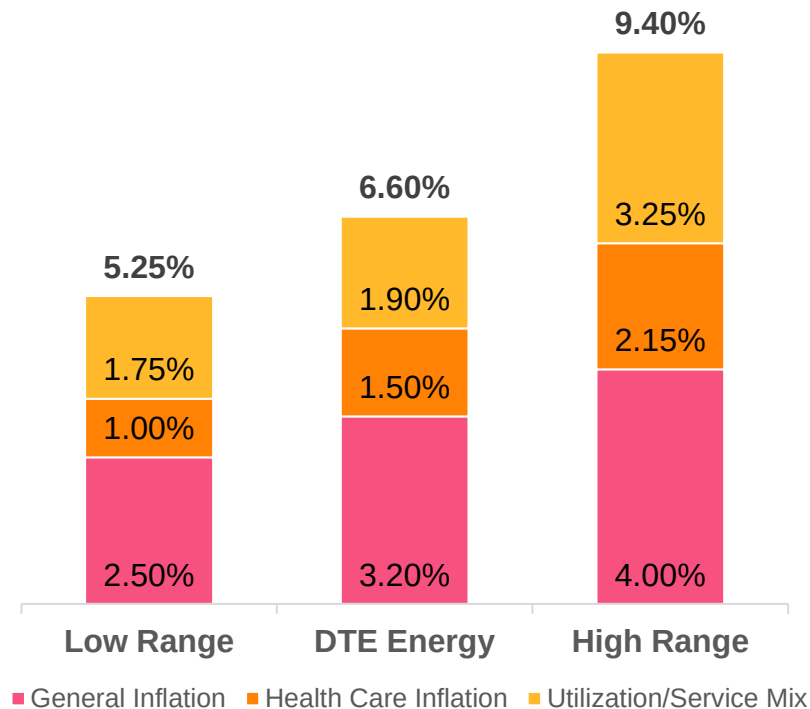
Historical trends are not the best predictor of future trends and are not appropriate without an analysis of the drivers of past trends and a consideration of potential future changes that may affect both the unit cost and utilization components in trend

	Allowed Trend			Plan Design Trend
Definition	Measures changes in unit cost, utilization and service mix			Measures allowed trend, plus the impact of trend leveraging against fixed cost sharing designs (i.e., deductibles, copays, and out-of-pocket maximums)
	• General inflation July 2022 – July 2023	3.2%	Source BLS	
	• Medical inflation above general inflation: typically 1% to 2.15%	1.5%	Assumed	
	DTE data • Increase assumed from utilization and service mix • Increase from breakthrough GLP-1 and oncology • DTE Energy has a large prevalence of oncology	<u>1.9%</u>	Merative risk score methodology GLP-1/weight loss medication Cancer drug pipeline	
	• Total	6.6%		
Sources	- WTW’s book of business and national surveys (Financial Benchmarks Survey) - United States government offices and agencies (CMS, CBO, BLS) - Third-party data sources (Merative MarketScan, Health Care Cost Institute, Kaiser Family Foundation) - DTE Energy data from Merative Advantage Suite database			WTW’s recommended plan trends consider national allowed trends and DTE Energy-specific plan design leveraging, rather than historical DTE Energy trend experience

1. Plan Trend is used for DTE Energy’s forecasting

Allowed Trend - Building Block Approach

Medical and Prescription Drugs (2022 to 2024)



General Inflation

- 2.5% is the lower bound of the Fed's December 2022 forecast
- 4.0% is slightly above the upper bound of the Fed's December 2022 forecast
- General inflation June 2022 through July 2023 is 3.2% per BLS
- Major externalities outside of the Fed's influence include the war in Ukraine and COVID-19

Incremental Health Care Inflation

- Health care inflation is likely to revert to the historical pattern of exceeding general inflation
- Labor shortages are becoming more acute
- Expectations of future inflation written into recent three- to five-year contracts between carriers and health care providers likely to mitigate the rate of decrease once inflation begins to abate

Utilization/Service Mix

- Historically, US utilization has been about 1.75% of trend
- Recent disruptions to access to care may result in additional future utilization.
- Merative risk analysis shows anticipated medical cost of DTE Energy increasing 5.3% (assume about 1.7% per year for 3 years)
- Based on DTE data, impact from specialty Rx expected to be 0.5% to 1.0% per year

Source: <https://www.bls.gov/news.release/cpi.nr0.htm>.

Merative Background

Merative is a data warehouse that combines trusted technology and real world expertise to help leading organizations improve their decision making and performance. They work with more than 4500 clients across the health ecosystem including:

- 4,000+ providers including 9 of top 10 US hospitals
- 40% of Fortune 100 employers and 7 of the top 9 US health plans
- 35+ state, local and federal government agencies
- All top 20 pharma

Medical risk score represents a measure of expected medical cost relative to an average person based on age, gender and all diagnoses during the time period. A medical risk score of greater than one means costs are predicted to be higher compared to the average person.

- **Concurrent Relative Risk Score:** An indicator of the expected relative cost risk of a patient compared to the average, based on claims experience between 6/1/2022 and 5/31/2023
- **Prospective Relative Risk Score:** An indicator of the expected relative cost risk of a patient compared to the average, in the year subsequent to the experience period

DTE Energy Concurrent Relative Risk Score	DTE Energy Prospective Relative Risk Score	% Change
.563	.593	5.3%

1. Risk scores are proprietary and developed by Merative

Plan Trend

Medical and Prescription Drugs (2022 to 2024)

Plan cost trends for 2023 are expected to be **6.5% for medical** and **9.0% for prescription drugs for composite trend of 7.1%.**

- Fixed-level provisions (i.e., deductibles, copays, and out-of-pocket maximums) cause member cost sharing to increase at a lower rate than allowed costs
 - Trend leveraging was estimated based on DTE Energy’s actual claims experience for self-funded plans in 2020, 2021 and 2022
 - WTW estimates the impact of trend leveraging against fixed-level cost sharing provisions to be approximately 0.5% for medical and prescription drugs across all plans

Component	Allowed Trend	Estimated Effect of Leveraging	Plan Trend	% of Claim Cost ¹
Medical	6.0%	+0.5%	6.5%	75%
Prescription Drugs	8.5%	+0.5%	9.0%	25%
Composite	6.6%	+0.5%	7.1%	100%

1. Average claim distribution for DTE Energy based on DTE’s experience for calendar year 2022.

Future Plan Trend Expectation

Medical and Prescription Drugs

- Medical and prescription drug cost trends are expected to remain relatively stable in the short term, barring any significant industry or regulatory changes
- Elevated inflation poses a significant risk to short-term claim trends. Trend expectations for 2023 and 2024 have increased to account for this risk
- Medical and prescription drug plan trends will be used by WTW to project historical experience to the projection period for rate setting, before plan design and other program changes are considered
- WTW will review and update prospective trend assumptions annually

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Plan Years	Trend Rate
2023	7.10%
2024	7.50%
2025	7.00%
2026	6.50%
2027	6.50%



PwC Health Research Institute

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Medical cost trend: Behind the numbers 2024

Increased pressure in healthcare





Heart of the matter: The cost of treating patients is on the rise

In 2022, inflation in the United States reached rates not seen since the 1980s.¹ With rising wages and expenses compounded by clinical workforce shortages, providers across the nation are fighting against declining profit margins. In turn, health plans are pressured to raise reimbursement levels in price negotiations with providers.

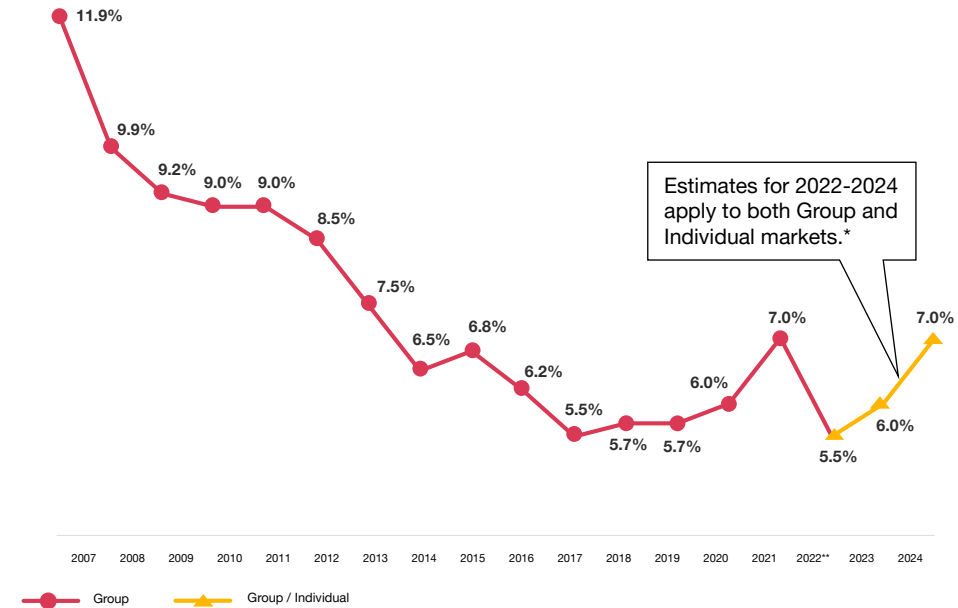
On May 11, 2023, the Public Health Emergency (PHE) officially ended, symbolizing a new stage in the pandemic. The past three years have seen not only a concerted effort to make available safe and effective COVID-19 diagnostics, therapies, and vaccines, but also shifts in how and where Americans gain access to care with an acceleration in technology and alternative sites of care. While some of these changes are temporary, others will likely persist into the post-pandemic world and become a different future.

PwC's Health Research Institute (HRI) surveyed and spoke with actuaries working at US health plans to generate an estimate of medical cost trend for the coming year. After considering various inflators and deflators of cost, HRI is projecting a 7.0% year-on-year medical cost trend in 2024 for both Individual and Group markets. This trend is higher than the projected medical cost trends in 2022 and 2023, which were 5.5% and 6.0%, respectively (see Figure 1). The higher medical cost trend in 2024 reflects health plans' modeling for inflationary unit cost impacts from their contracted healthcare providers, as well as persistent double-digit pharmacy trends driven by specialty drugs and the increasing use of the GLP-1 agonists for Type 2 Diabetes or weight loss. PwC updated its 2022 medical cost projection for the Group market to 5.5%, 1.0% down from the initial projection in 2022, primarily driven by a shift in sites of care from inpatient hospital settings to less costly alternatives such as outpatient and ambulatory surgical centers.

The inflationary impact is further exacerbated by continued clinical workforce shortages in 2023-24, prompting hospitals to increase salaries and consequently seek higher reimbursement from payers. On the pharmacy side, the introduction of new [cell and gene therapies](#) (11 approved in the past three years) is a key inflator expected to increase the median price of treatment going into 2024.

Although health plans reported some deflationary relief through shifts in site of care and the introduction of biosimilars, the overall impact is muted by the various inflators.

Figure 1: PwC Health Research Institute medical cost trends, 2009-2024
HRI projects medical cost trend to be 7.0% in 2024, up from 6.0% in 2023



Source: PwC Health Research Institute medical cost trends, 2009-2024

*For 2022-2024, medical cost trend was estimated separately for Group and Individual market based on the surveys and interviews conducted April-May 2023. HRI found no significant difference in the estimates for the two markets.

**The 5.5% medical cost trend for 2022 was revised from 6.5% originally projected in PwC Health Research Institute's "Medical Cost Trend: Behind the Numbers 2022" report, released in 2021. This revision reflects the average medical cost trend that was used for 2022 premium rate setting in 2021, shared with HRI during surveys and interviews.

See "About this research" for more details.

Inflators

Inflation and its ramifications across the healthcare landscape are the main factors driving spending in 2024.

- Inflationary impacts on healthcare providers.** Hospitals and physicians are expected to seek higher rate increases (potentially also at a higher frequency) in contract negotiations. Workforce shortages and physician consolidation can further amplify the effect. Further, provider “burnout” and increased patient demand are expected to keep the pressure up on clinical workforces across the industry.
- Increasing cost of pharmaceuticals.** Plans are experiencing inflationary pressure from the rising median price of new drugs, as well as the increasing price of existing drugs. Combined with the accelerated approvals of new cell and gene therapies, pharmacy trends are not expected to slow down in 2024.

Deflators

Some positive changes in the pharmaceutical market and care setting are expected to help counteract inflationary pressure, but their effect will be overshadowed by the inflators.

- Biosimilars coming to market.** The prices of biosimilars are, on average, more than 50% lower than the reference products at the time of biosimilar launch. The launch of adalimumab biosimilars to Humira in 2023 is a new milestone in the market that is already driving significant savings.
- Shift in site of care.** Plans reported a decrease in inpatient utilization as well as a shift towards outpatient care, allowing a two-pronged benefit to contain costs.

Recent reports of increases in outpatient utilization among Medicare plans was not commented on during the research period for this report.

Trends to watch

In addition to the inflators and deflators summarized in this report, there were several other factors reported by health plans as being impactful for trend development, but were not considered a significant trend bender as an inflator or deflator.

- Total cost of care management.** Many health plans continued to invest in total cost of care management initiatives such as value-based care that helped maintain year over year trend. National health plans generally demonstrated better cost management and subsequently achieved lower cost trends. As these national plans continue to grow, they will have a deflator effect overall on medical cost trends.
- COVID-19.** Impacts of changes in federal and state policies and the need for vaccines, testing and treatment vary, with the net effect likely being neutral. Health plans did not report a causal relationship between pent-up demand for care during the pandemic and utilization of care. The consensus among health plans is that inflationary pressures continuing in 2023 and going into 2024 will be driven by provider unit cost increases and pharmacy trends rather than a recovery in surgery utilization post-pandemic.
- Health equity.** Health equity is a focus of every health plan. The impact of related efforts to improve population health in the long term has not yet factored into plans’ cost of care models. Further, all plans are still working through CMS guidance on health equity.
- Behavioral health.** While utilization of behavioral health grew during the pandemic and continues to grow, its cost remains relatively lower than other medical costs. Health plans did not account for behavioral health in their pricing and forecasting.

- Centers for Medicare and Medicaid Services (CMS) Price Transparency Rule.** Health plans expect the impact of this rule on the 2024 trend will be neutral, given the immaturity of the data. In the long run, plans could see both upward and downward pressures.
- Medicaid redetermination.** The impact is likely to be felt in the Individual market only, with magnitude and direction depending on the number of disenrollees who eventually purchase Individual plans and their risk profile.

This year, the scope of this report was broadened to include both small and large group ("Group")² and ACA marketplace ("Individual") plans.

The Individual market has seen significant growth from 12 million in enrollment in 2021 to 16.4 million in 2023. In addition to Individual market-focused plans, all major health plans in the group market also offer plans in the Individual marketplace, where competition has intensified in recent years. The impact of major factors driving medical cost is mostly felt in a similar way across the two markets. Meanwhile, there are distinct considerations that apply to one of the markets, most prominently Medicaid redetermination and network adequacy for the Individual market.

This report does not focus on trends in Medicare and Medicaid.

What is medical cost trend?

Medical cost trend is defined as the projected percentage increase in the cost to treat patients from one year to the next, assuming benefits remain the same. While medical cost trends can be defined in several ways, this report estimates the projected increase in per capita costs of medical services and prescription medications that affect insurers' Group and Individual plans. Insurance companies use the projection to calculate health plan premiums for the coming year. For example, a 5.0% trend means that a plan that costs \$10,000 per member this year would cost \$10,500 next year. The medical cost trend, or growth rate, is influenced primarily by:

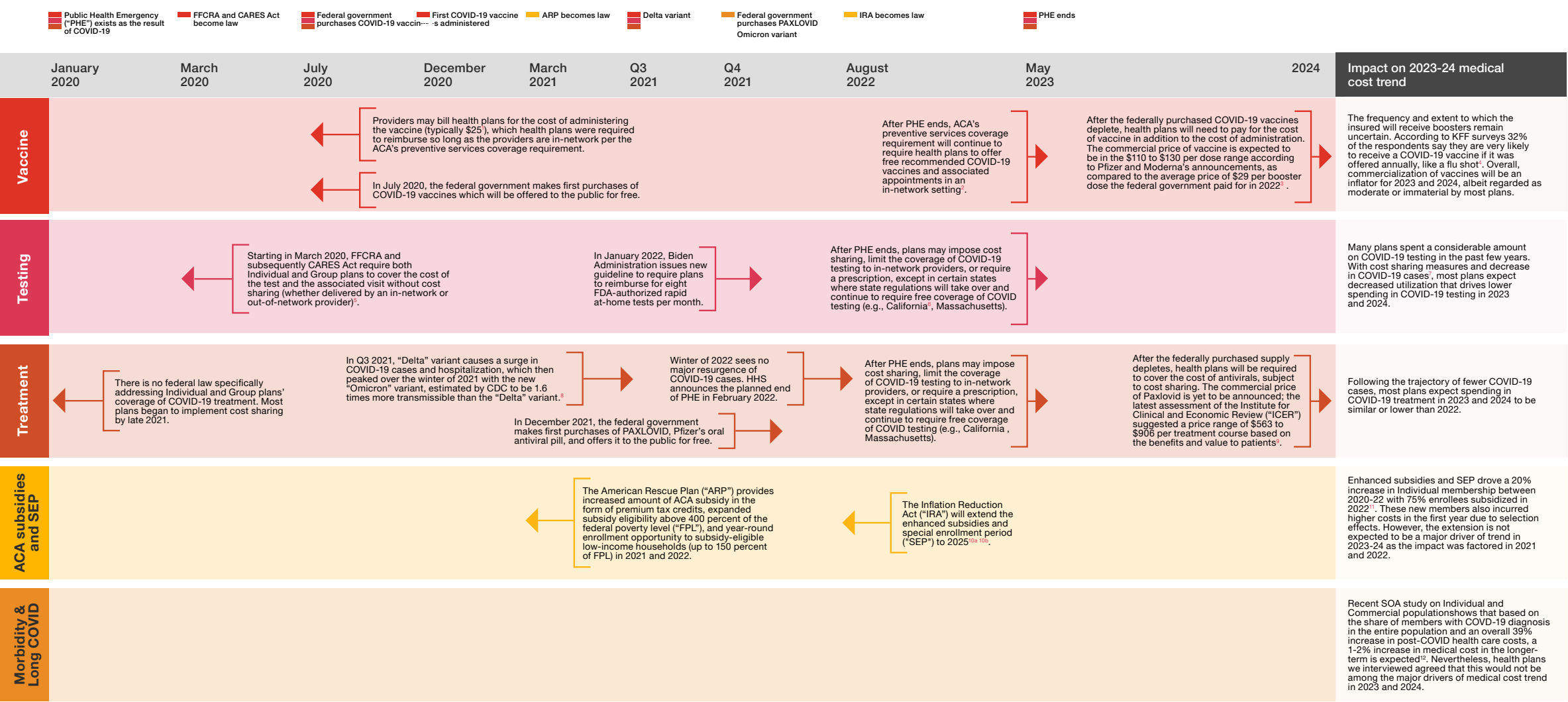
- Changes in the price of medical products and services and prescription medications, known as unit cost inflation.
- Changes in the number or intensity of services used or changes in per capita utilization.



COVID-19 timeline:
From pandemic to present

On May 11, 2023, Public Health Emergency (“PHE”) officially ended, symbolizing a new stage in our co-existence with the COVID-19 pandemic. The past three years have seen not only a concerted efforts to make available safe and effective COVID-19 diagnostics, therapies, and vaccines, but also shifts in how and where Americans gain access to care. While some of these changes are temporary, others will persist

into the post-pandemic world and become the new-normal. The timeline below looks both past and ahead at the key events that impacted and will impact health plans’ spending. Overall, our survey and interview indicated a consistent view among health plans that different factors as laid out below tend to cancel out and the net impact is expected to be neutral or immaterial as compared to other major inflators / deflators.



1. <https://www.healthsystemtracker.org/chart-collection/where-do-americans-get-vaccines-and-how-much-does-it-cost-to-administer-them/>
2. <https://www.kff.org/womens-health-policy/fact-sheet/preventive-services-covered-by-private-health-plans/>
3. <https://www.kff.org/coronavirus-covid-19/issue-brief/how-much-could-covid-19-vaccines-cost-the-u-s-after-commercialization/>
4. <https://www.kff.org/coronavirus-covid-19/poll-finding/kff-covid-19-vaccine-monitor-march-2023/>
5. <https://www.doi.gov/sites/doi.gov/files/EBSA/about-ebbsa/our-activities/resource-center/facts/aca-part-51.pdf>
6. <https://www.dhcc.ca.gov/Portals/0/Docs/DO/COVID-FactSheet2022.pdf>
7. <https://www.hhs.gov/about/news/2023/02/09/letter-us-governors-hhs-secretary-xavier-becerra-renewing-covid-19-public-health-emergency.html>
8a. <https://coronavirus.jhu.edu/region/united-states-8b>
9. <https://www.cdc.gov/museum/timeline/covid19.html>
10. <https://www.healthinsurance.org/loss-at-inflation-reduction-act/>
11. <https://www.kff.org/policy-watch/as-aca-marketplace-enrollment-reaches-record-high-fewer-are-buying-individual-market-coverage-elsewhere/>
12. <https://www.soa.org/resources/research-reports/2023/hcc-covid-effects-longterm/> The study does not publish the total cost of members with versus without COVID-19 diagnosis. Based solely on member count of 626,142 with COVID-19 diagnosis and total membership of 33.0 million over the three-year period, the impact on overall medical cost trend will be approximately 0.7%. However, the members with COVID-19 diagnosis includes high-risk groups and are likely to have higher overall cost than the rest of the population; thus the impact on overall medical cost trend shall be higher than 0.7%.

Inflator:

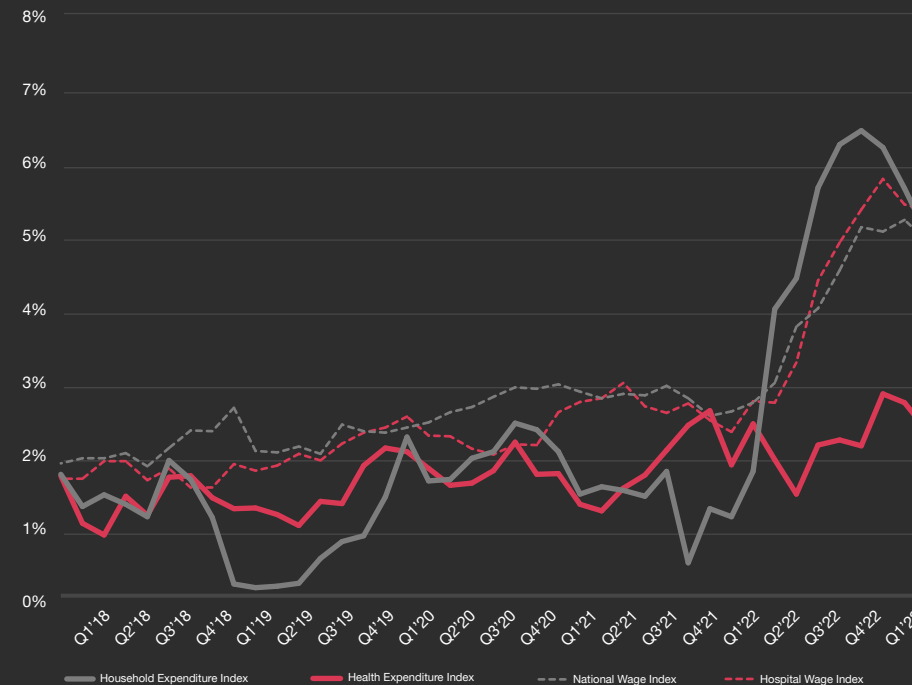
Inflationary impacts on healthcare providers

Inflation in the United States has reached rates not seen in decades. All health plans ranked inflationary impacts on providers among the top three inflators for 2024.

In 2022, while inflation was felt across the US economy, its impact on healthcare spending was dampened by existing annual or multiyear provider contracts. Figure 2 illustrates the lag between the household expenditure index, with a rise starting in the second quarter of 2021 and persisting at a high rate of 6.0% or more throughout 2022, and the health expenditure index, with a modest 2% to 3% increase. Generally, health expenditure inflation lags behind hospital wage inflation.

In a persisting high inflationary environment, hospitals and providers will ultimately be pushed to seek significant rate increases from payers. Many health plan actuaries said they are facing increasing inflationary pressure on unit cost in 2023 and 2024. Their ability to manage price increases during contract renewals will be a key factor in determining how the impact of inflation will materialize in the coming years.

Figure 2: Expenditure and Wage Indices year-over-year growth 2017-2022



Source: Bureau of Labor Statistics Consumer Price Index, PwC analysis

Clinical workforce shortages add to the contractual pressure from providers

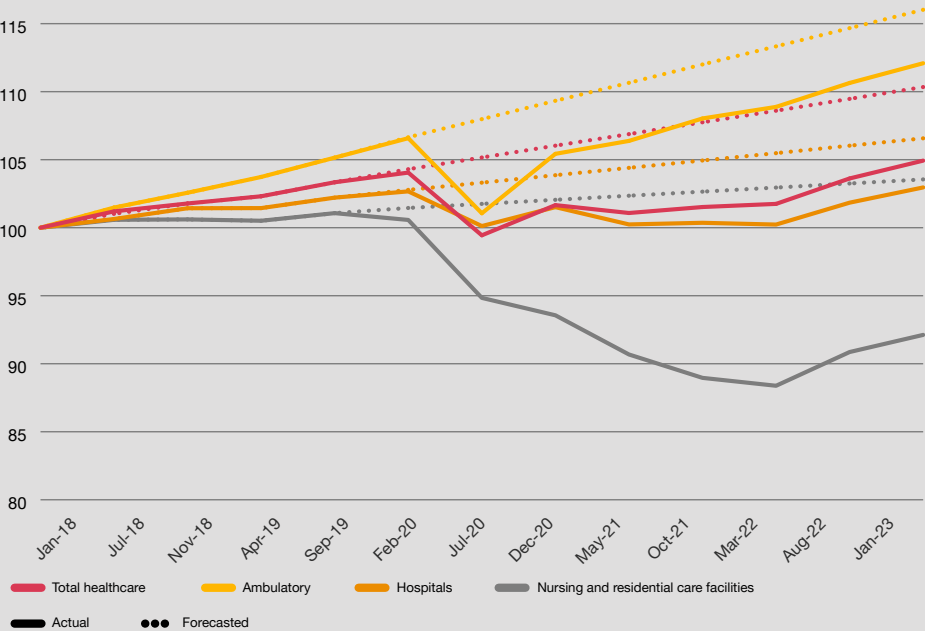
Healthcare employment plummeted during the pandemic, leading hospitals to incur much higher labor costs. During the peak of the pandemic in 2021, hospitals experienced an estimated 16% increase in labor expenses per adjusted discharge compared to September 2019³, not only due to paying higher wages but also from using temporary clinical staff through “traveler agencies” that can often charge high prices.

Though healthcare employment started to steadily recover in 2022, total employment still has not returned to pre-COVID levels, and a noticeable gap persists for the nursing/residential care facilities segment.

Several health plans expect no short-term resolution of the clinical staff shortage. Assuming the persistence of such shortages in 2024, hospitals will continue to be financially challenged and forced to seek higher reimbursement from payers. On the other hand, if healthcare employment levels return to a stable level in 2024, pent-up demand for care is likely to drive utilization up. In both cases, health plans can expect to face inflationary pressure in 2024.



Figure 3: Healthcare employment - actuals vs. pre-COVID forecast index 2017-2022*



Source: Bureau of Labor Statistics Employment Cost Index, PwC analysis
*Forecasted employment (dotted lines) is estimated by applying pre-COVID employment growth rates.

Hospital, private equity and other physician consolidation amplifies the inflationary pressure

Recent physician practice acquisition activities, including actions by hospitals, private equity firms and insurers amplify the inflationary pressure during contract renewals. Studies find that such acquisitions accelerated during the COVID-19 pandemic, and over the three-year period starting from 2019, the percentage of physicians employed by hospitals or corporate entities increased by 62% to 74% (Figure 4).⁴ Specifically, private equity activities in the healthcare services sector set record highs in 2020-2022.⁵ The ongoing consolidation of physician groups is expected to compound the inflationary pressure on medical cost in the near term.⁶ In the long term, many consolidated physician groups aim to enter value-based care and thus lower total cost of care.

Individual market can be most impacted

We note potentially a higher impact of inflation on the Individual market due to network configuration. Compared to the Group market, more Individual plans utilize a narrow network to lower consumer premiums. Plans typically negotiate more favorable rates with select providers through membership steerage. These lower rates are expected to command a higher increase on a percentage basis to compensate for inflation, compared to the higher rates in the wide network plans that dominate the Group market, as illustrated in Figure 5.

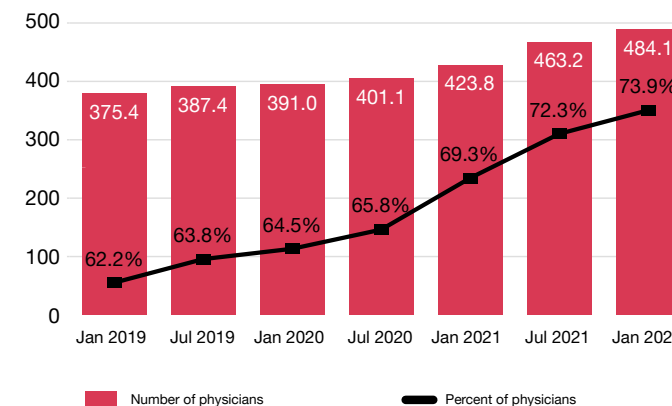
Implications

Health plans and payviders: Confront affordability and disrupt costs. Health plans will encounter greater unit cost increase pressure from providers, which can play out for several years to come. Health plans should rethink their strategies as affordability is key to winning in the Individual and Group market. Value-based care, targeted care management, versatile in-house data analytics and harnessing the power of AI technology can help plans aggressively counteract the forces of inflation.

Providers: Solve systemic clinical workforce shortages, which have led to significant margin losses and, in some cases, even hospital closures. Providers should be proactive in attracting healthcare talent and doing more with less while also moving quickly to leverage technology such as AI to ease the workforce strain.

Employers: Because of continued talent concerns, employers are generally not expected to increase employee cost sharing. Instead, there will be an increased emphasis on network strategies, including the use of narrow/high-performing networks, centers of excellence to target high-cost claims (particularly cancer and orthopedic cases), plan designs that steer patients to lower-cost providers, and a renewed attempt at finding effective navigation tools.

Figure 4: Number and percentage of U.S physicians employed by hospitals or corporate entities 2019-21



Source: Physician Advocacy Institute report on COVID-19's impact on acquisitions of physician practices and physician employment 2019-2021

Inflation and clinical workforce shortages will continue to exert pressure on healthcare.

Source: PwC Medical cost trend: Behind the Numbers 2024



Inflator:

Increasing cost of pharmaceuticals

The new pharmaceutical pipeline is anticipated to be a strong headwind to any medical cost trend improvement. The median annual price for new drugs being approved by the U.S. Food and Drug Administration's (FDA) Center for Drug Evaluation and Research (CDER) increased from \$180,000 in 2021 to \$222,000 in 2022, implying double-digit annual growth in price.⁷ This underlines a historical trend that led to median launch prices increasing from ~\$2,000 per year in 2008 (37% annualized growth).⁸ This surge in price is driven by a concurrent increase in the approval of high-cost drugs. The proportion of approved drugs priced at \$150,000 per year or more was 9% in 2008-13 but increased to 47% in 2020-21.

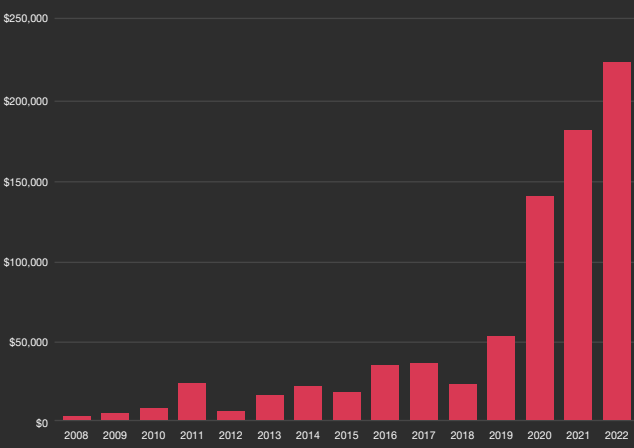
Pharmaceutical manufacturer pricing is expected to be in the high single or double digits from 2023-2024. New drugs typically exist in the market for 15 years on average without competition from generic drugs, along with general increases in drug prices over time. Multiple insurers report that the trend used for pricing 2023 plans was lower than actual experience, driven by higher-than-expected pharmacy trends for both brand and specialty drugs. Plans also reported facing consistently increasing average wholesale price (AWP) over the last two years and do not anticipate this trend to flip.



This inflation is compounded by drug shortages and supply chain issues. In a report to Congress from the Office of the Assistant Secretary for Planning and Evaluation (ASPE), an analysis of the data showed a 16.6% increase in the price of drugs in shortage, driven mostly by an increase in the price of generics (14.6%).⁹

The largest increase in the number of drugs experiencing an increase in price was in 2021-22, and 2022 observed the largest historical increase in the average price (Figure 6).¹⁰

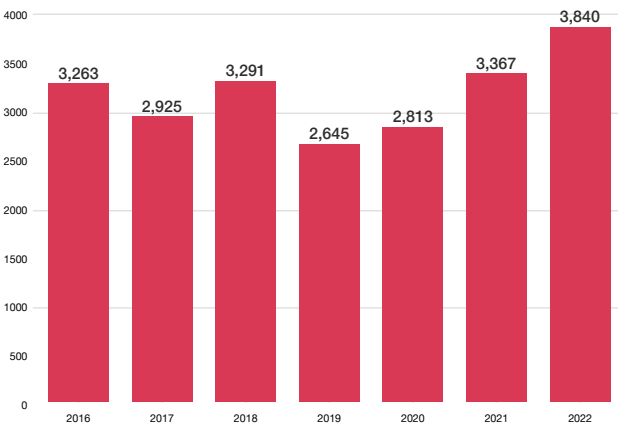
Figure 5: Median price of newly marketed drugs 2008-2022



Source: Trends in Prescription Drug Launch Prices, 2008-2021; Reuters survey⁸

Figure 6: Number of drugs with price increases per year and average dollar price changes per year 2016-2022 (January and July only)

Number of drugs with price increase per year



Average dollar price change per year



Source: Price Increases for Prescription Drugs, 2016-2022¹⁰
*Based on January and July price increases only; the research finds that these months historically account for most of the increases that occur each year.

New cell and gene therapies

Inflationary impacts from new drugs go hand-in-hand with the introduction of new cell and gene therapies. Of the 29 gene therapies currently approved by the FDA, 11 have been approved since 2021. Another 30 are in late-stage development with the potential for future approval. However, the development of these therapies includes extensive costs that will be passed on to payers who are already navigating an uncertain post-pandemic utilization and cost dynamic.

Payers are responding by more thoroughly assessing the cost/benefit of therapies in their coverage decisions, contracting with manufacturers to tie reimbursement to real-world evidence, exploring alternative financing arrangements (including stop-loss policies), and enacting prior authorization and other controls to manage drug utilization.

Some key gene therapies on payers’ radars include Hemgenix, which was approved by the FDA in November 2022 as a one-time treatment for patients with Hemophilia B and cost \$3.5 million; and Roctavian for severe Hemophilia A, expected to be approved in 2023 following European approval in 2022. In the first half of this year, three additional gene therapies are expected to be approved, and they will likely be highly priced, putting increased pressure on the healthcare system.¹¹

GLP-1 (Glucagon-like Peptide-1) Agonist drugs in diabetes and obesity

In the US alone, about 130 million adults may become eligible for GLP-1 agonist medications because of their weight and other health conditions.¹² The prohibitive cost (upwards of \$10,000 a year), however, has kept utilization down. Ozempic, Novo’s weekly GLP-1 shot for diabetes, went on sale in 2018, followed in 2021 by Wegovy, a higher dose of the same medication developed for obesity.

Eli Lilly’s Mounjaro, approved for diabetes last year, has shown even more dramatic weight loss results through a large trial published last year and reinforced through another trial this year.¹³ Lilly is filing for approval to treat obesity. Wegovy, which has approval as an obesity treatment, costs more than \$17,000 a year — 40% more than Ozempic, which is the same drug in a smaller dose.¹⁴

At the moment, most health plans do not cover the use of GLP-1 agonists for nondiabetic treatment unless specifically approved as a prescription weight-loss drug, meaning a drug like Ozempic is not being covered for weight-loss use. However, the FDA has already set a precedent after approving Wegovy in 2021¹⁵ and perhaps Lilly’s Mounjaro in the future. Should the FDA approve all of these drugs for weight-loss, utilization can be expected to increase substantially going forward.

Figure 7: List of gene therapies to watch

Gene Therapy	Estimated Cost
Abecma™	\$482,000 per suspension
Astiladrin*™	\$160,000 - \$260,000 per therapy
Breyanzi™	\$471,000 per suspension
Carvykti™	\$500,000 per suspension
Hemgenix™	\$3,500,000 per dose
Omisrige™	\$338,000
Rethymic™	\$2,700,000 per implant
Skysona™	\$3,000,000 per infusion (single use)
Vyjuvek™	\$25,000 per vial
Zynteglo™	\$2,800,000 per infusion (single use)

Source: PwC analysis
*Forthcoming in 2H 2023



Implications

Health plans and payviders: Track new pipeline and related costs closely for accurate modeling

Payers are anticipating the new pharmaceutical pipeline will increasingly drive the medical cost trend. Plans have begun modeling double-digit pharmacy trends into their cost projection models to avoid underestimating overall cost trend heading into 2024 and beyond. The recent growth in the number of approved gene therapies is expected to drive cost to a historic high as consumers shift to alternative medicines. Adding to this, as the scope of physician prescriptions widens to allow GLP-1 agonist drugs to be prescribed for weight loss, plans will have a new challenge in 2024. Formulary management will be a key consideration for health plans.

Pharmaceutical manufacturers: Adjusting to regulations, removal of Medicaid rebate cap, and other impacts while navigating continued public pressures

Pharmaceutical manufacturers face pricing and Gross-to-Net impacts from regulatory changes, such as the Inflation Reduction Act (IRA) and the removal of the cap on Medicaid rebates based on average manufacturer price (AMP) in 2024. Pressure continues to be applied from potential federal and state government legislation, increased PBM/ payer utilization management and competitive RFPs, patient copay and assistance program dynamics, and other key trends. Manufacturers will face continued challenges as they balance optimally enabling patients access to their therapies while continuing to invest in R&D and innovation.



Deflator:

Biosimilars coming to market

The FDA defines biosimilars as a biological product that is “highly similar” to and has “no clinically meaningful differences” from an existing FDA-approved reference product.¹⁶ The adoption of biosimilars to specialty drugs has substantial potential to manage rising drug costs.

Research finds that, on average, biosimilar sales prices are more than 50% lower than the reference product’s price was at the time of the biosimilar launch, and similarly, the sales price of brand biologics competing with biosimilars fell on average 25% since the biosimilar launch.¹⁷

This year, there is a new milestone in the biosimilar market — the arrival of the first biosimilar to a major specialty drug — adalimumab biosimilars to Humira™. In 2022, the revenue from this blockbuster drug totaled more than \$18 billion in the US.¹⁸ In January 2023, Amgen launched its adalimumab biosimilar, Amgevita™, and to date, the FDA has approved nine adalimumab biosimilars and most others are likely launching within a year following Amgevita™.¹⁹

As a reference point for the potential savings, Amgevita™ was launched with two price points, one 55% below Humira™’s list price and the other 5% below, the latter likely coming with larger rebates to the payers²⁰ and plan sponsors. Health plan actuaries also reported manufacturers offering larger rebates for their flagship drugs to retain market share.

Overall, the biosimilar market continues to accelerate. Figure 7 shows biosimilars to 15 reference biologics in the pipeline for 2023-25, as compared with only two approved by the FDA in 2020-22. Moreover, heightened regulatory interest and support have been reflected in a comprehensive plan for addressing high drug costs published by the US Department of Health and Human Services (HHS) earlier in 2021, which calls out “promote biosimilars and generics” in one of the three guiding principles.²¹

Many health plans are watching biosimilar trends and conducting assessments to understand their impact. For 2024, the savings from biosimilars are expected to have a relatively moderate impact on the overall medical cost trend (two health plans cited expected impacts close to -0.5%), given biologics with existing biosimilars make up a small portion of the overall medical cost. Nevertheless, 65% of health plans surveyed ranked biosimilars coming to market among their top three deflators, and many have hopes of more savings to come.



Implications

Health plans and payviders: Evaluate options to integrate biosimilars into pharmacy benefits

The idea that biosimilars offer lower-cost alternatives to biologics is simple, but the actual implementation can be complex. For health plans, the first step is likely to be working closely with pharmacy benefit managers to understand which biologic/biosimilar(s) is the most cost-efficient — sometimes staying with the existing biologics might be as cost-efficient as switching to biosimilars through competition-driven larger rebates. Next, health plans may explore alternative cost sharing design and utilization management tools, such as prior authorization that can be leveraged to incentivize members towards more cost-efficient options. An important consideration is the impact on member experience should the plans change existing benefit terms. Additionally, plans should consider potential increased utilization if the price of previously expensive drugs becomes more accessible. All the various factors need to be weighed and each health plan may make a different decision depending on its unique priority and membership characteristics.

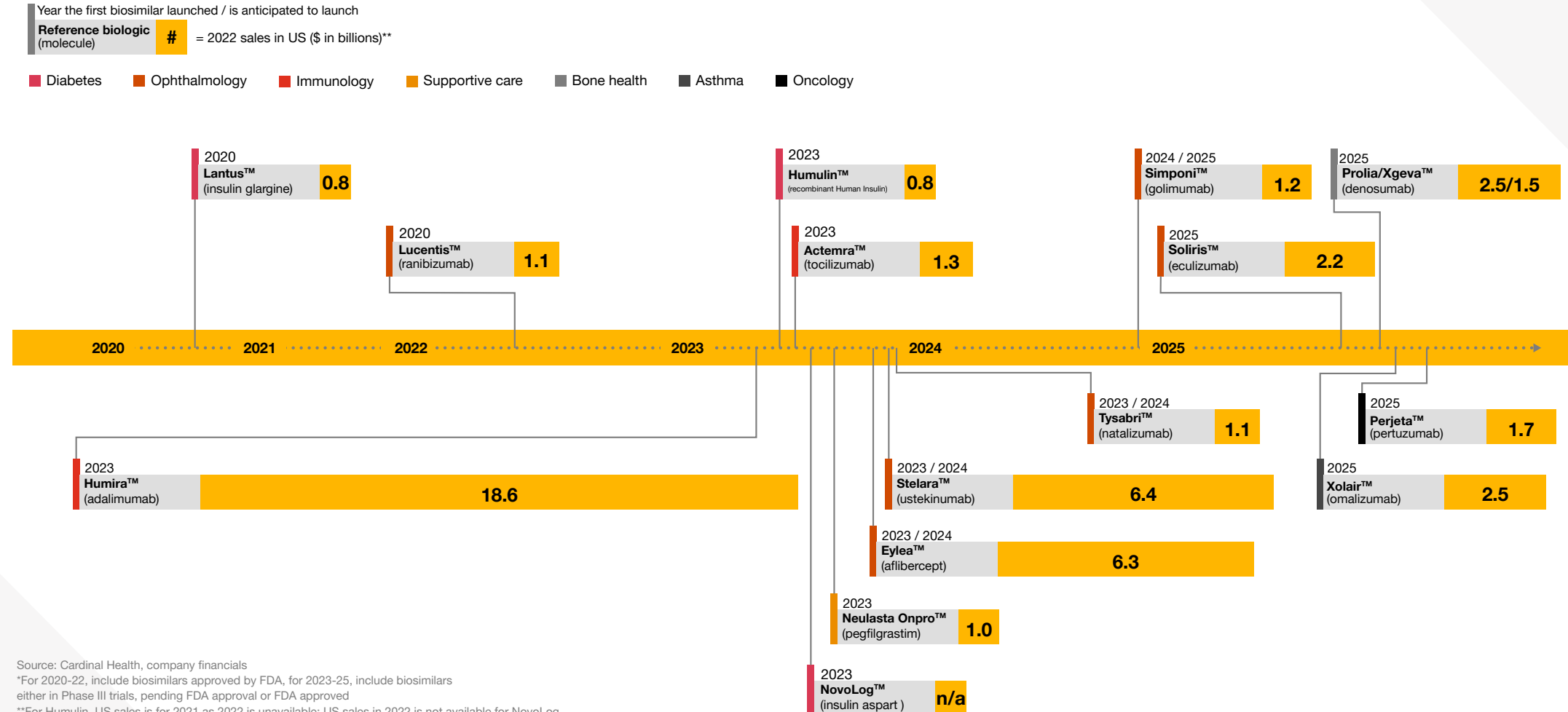
Pharmaceutical manufacturers

While biosimilars have grown and carved out a space on the medical benefit side, particularly within physician-administered drugs in oncology, biosimilar market maturity within the pharmacy benefits space is just beginning. The entry of Lantus biosimilars last year and Humira™ this year have provided the first and largest tests of biosimilar penetration on the pharmacy benefit, with growing tests throughout 2023 (January Amgevita™ launch, multiple launches in July). Despite the uncertainty, there are some early strategies and implications emerging. First, manufacturers have launched with both high and low wholesale acquisition cost versions to appeal to different market segments, a trend that shows no sign of stopping with the Coherus + Mark Cuban Cost Plus Drugs recent announcement. Second, biosimilar entry in some cases replaces the innovator on the formulary and in other cases is disadvantaged / excluded vs. the innovator. Every entry has come at the expense of the innovator’s Gross-to-Net. Payers/PBMs are leveraging biosimilar entry to lower the cost of these drugs, and at times the entire class/therapeutic area. The industry will keep watching for any future regulatory/legislative actions that impact the biosimilar market as many players appear to remain committed to near and long-term growth of the biosimilar market.

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Figure 8: Historical and anticipated future biosimilar launches 2020-25*



Deflator:

Shift in site of care

The pandemic revolutionized the dynamics of the US healthcare system by rapidly shifting the site of care from more expensive inpatient hospitals to less expensive outpatient. While this trend started before the pandemic with cataracts and cosmetic surgery in the 2000s, it accelerated toward the end of the pandemic when employment in ambulatory care settings recovered the fastest.

As a result, lower-cost freestanding and non-acute sites were able to absorb a large portion of the demand for these healthcare services that were previously only available through inpatient settings.

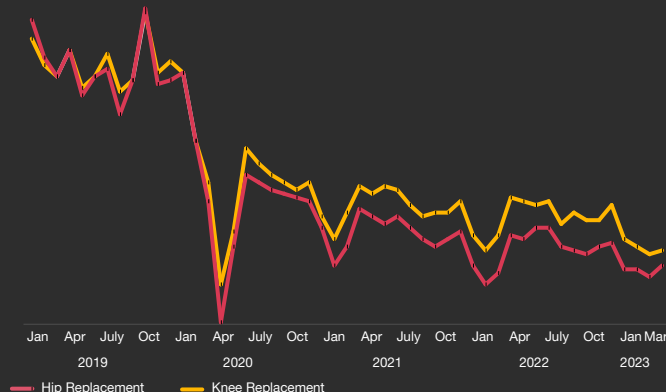
With the increased demand for outpatient surgeries, home-based services and virtual care, the healthcare delivery system has reached a new phase. Plans are factoring in higher utilization of less expensive in-person settings and virtual care going forward when pricing their 2023 plans and beyond.

Non-acute sites have lower costs for plans, which in turn is expected to decrease the share of revenue received by inpatient hospitals. With lower-cost in-person settings and virtual delivery setting the path going forward, the overall cost of care is expected to decline,²² helping plans offset the trend inflators.

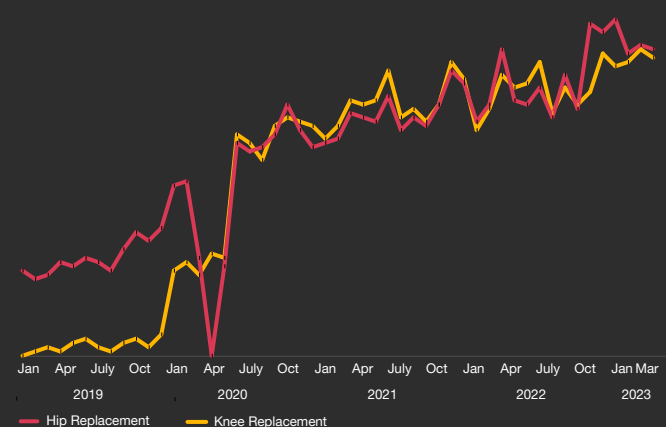
Plans have noted a material difference in the 2022 and 2023 expected trends as compared to actual experience when factoring in the uptick in utilization in less expensive in-person settings.

Figure 9: Shift in primary hip / knee replacement to Outpatient

National Volume Changes - Inpatient



National Volume Changes - Outpatient



Source: Strata National Patient and Procedure Volume Tracker



Implications

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Health plans and payviders: Model trend impact from shifting site of care and associated reduction in costs

The pandemic decreased inpatient utilization over the last two years — which has helped control the cost of care while also shifting care towards outpatient, allowing plans to reap the benefits from both aspects.

As inpatient surgery trends continue to decline every year, health plans do not know yet how much lower they will go and what their models will look like. There is enough evidence to support a deflationary impact on trend until inpatient utilization in general and surgery utilization, in particular, recovers to pre-pandemic levels, if at all.

Providers: Incentivize shift of care to gain a share in profits

Providers also have an important role to play. They can work with plans to establish ownership models that share financial gains and incentivize physicians to accelerate the shift to outpatient care. This will help ease the pressure on inpatient settings whose capacity has been the slowest to recover across the country driven by an acute lack of skilled labor.

It's important to note, however, that not all care can be shifted to ambulatory service settings and may not be appropriate for frail patients, for instance, or those with complex comorbidities. There needs to be clear criteria for defining use cases and when patients can safely be shifted to less costly in-person settings.

Recent reports of increased outpatient utilization among Medicare plans was not commented on by health plans during the research period for this report.

Employers: Encourage telemedicine for primary care and behavioral health

Through plan design changes and adding new third-party telemedicine vendors, employers will likely continue to encourage the use of telemedicine. Virtual visits for behavioral health have exploded in recent years, allowing for increased flexibility in addressing the pressing need for mental health treatment, especially to address significantly increased anxiety and depression issues among adolescent patients. Virtual primary care visits are expected to increase in the coming years as well.



Trends to watch

Not all trends are new or clear inflators or deflators of the medical cost, but they are important influencers to watch. These are the areas that we will be following over the next year to track and forecast medical cost trend.

Continued efforts to manage total cost of care

To confront the ever-rising costs, health plans have continued to execute and innovate.

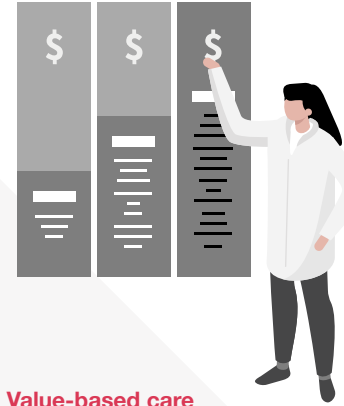
Value-based care, which better aligns incentives across payers and providers, has gained ground in recent years — analyses show that around 60% of health care payments in 2020 included some form of quality and value component, up from 38% in 2015.²³ For some plans, value-based care has proven to be a cost deflator. Meanwhile, long-standing efforts such as payment integrity and care management have continued to evolve with more sophisticated approaches and more advanced digital intelligence.

None of these cost strategies is new to the healthcare industry. National plans tend to lead in this sphere, given the high return on investment through scale. Meanwhile, more regional plans have been catching up — one plan actuary cited achieving a negative medical cost trend in 2022 by launching refocused cost of care programs. Any plan that has not made similar investments will likely need to do so soon to keep up with the market.

Overall, the largest players in the market reported a greater impact of cost of care initiatives on trend than smaller plans. Some regional players, however, reported large one-time deflators as they catch up in the implementation of these programs. As National plans acquire smaller regional plans, this category is expected to be a deflator for medical cost trend. In the meantime, for plans that are mature in managing total cost of care, the effects of such efforts have become part of the year-over-year baseline, not explicitly a deflator but helping to keep the trend at the same level.

The COVID hangover

Impacts of changes in federal and state policies and the need for vaccines, testing and treatment vary, with the net effect likely being neutral. Health plans did not report a causal relationship between pent-up demand for care during the pandemic and utilization of care. The consensus among health plans is that inflationary pressures continuing in 2023 and going into 2024 will be driven by provider unit cost increases and pharmacy trends rather than a recovery in surgery utilization post-pandemic.



Value-based care

Move along the pathway to value from fee-for-service to shared savings and capitation arrangements



Payment integrity

Intelligent and automated process both pre- and post-payment to reduce duplication, errors and fraud or abuse with minimal provider abrasion



Utilization management

Fast but informed decisions that ensure appropriateness and drive overall value of care



Care management

Target at the right member at the right time, broaden sources of value from both medical cost and revenue sides



Advanced data analytics

Accessible to all functions, help identify new opportunities and support existing business cases



Preventive Care & Wellness Programs

Improve both member experience and health outcomes



Behavioral health

While utilization of behavioral health grew during the pandemic and continues to grow, its cost remains relatively lower than other medical costs. Most health plans are not accounting for behavioral health in their pricing and forecasting.

During the COVID-19 pandemic, behavioral health (BH) and mental health/substance abuse services (MH/SA) saw a significant and consistent uptick in utilization. Outpatient visits related to this category trended upward in double digits year over year, reaching a new level of utilization. Omitting care for COVID-19, behavioral health visit volume was 16.8% above pre-pandemic levels in the first quarter of 2022.²⁴ Although the increase has slowed, health plans do not anticipate usage to go back down to pre-pandemic levels.

This large increase has been sustained across all types of BH services, whether it be in-person or telehealth and virtual care. When it comes to BH, plans reported a significant push from their consumer base for telehealth services during the pandemic that has continued since, growing from 32% pre-pandemic to 60% of all BH visits in the first quarter of 2022.²⁵ The growing focus on access to care improvement further motivated the use of telehealth services. An America's Health Insurance Plans (AHIP) survey covering 95 million lives showed that the number of in-network BH providers increased by an average of 48% in three years among commercial health plans, and that all plans provided coverage for telehealth services specifically for BH.²⁶ This trend to improve access will continue to be a hot topic as provider networks credentialled to provide these services grow and expand.

A related concern in this category is fraud, waste and abuse. A common example has been out-of-state behavioral health facilities that are covered by health plans to allow access to care but have limited, if any, oversight on the cost, quality and quantity of services being rendered. Striking the balance between network adequacy and fraud, waste and abuse will be a challenge for health plans going forward.

In most cases, while the dollars associated with these services are growing, they are still low and do not materially impact the trend development compared to other inflators. Additionally, recent studies have shown that promoting outpatient behavioral health (OPBHT) as a part of a population health strategy can help improve overall medical spending. Results indicate that healthcare costs for patient groups with OPBHT use were 10%-15% lower compared to those without OPBHT visits.²⁷ These findings support the cost-effectiveness of OPBHT utilization, which can act as a deflator on overall medical cost trend in the long term.

Health equity

Health equity is a focus area for health plans, although the impact of population health efforts was not factored into their medical cost trend. A broad array of factors within and beyond the healthcare system — including social, economic, and environmental factors — drive disparities in health and healthcare. Recent years have seen increasing attention and resources invested to address such disparities. On the regulatory side, the CMS published its Framework for Health Equity 2022-2032, stating its “unwavering commitment to advancing health equity” and, in practice, introduced new policies with reference to health equity to Medicare (ACO REACH benchmark adjustment)²⁸ and the individual marketplace (network adequacy).²⁹ Health equity is an important topic among health plans.

Network adequacy is a measure to ensure more equal access to care in the rural areas. On the Individual market, in the 2023 Final Rule³⁰ CMS set forth that it will resume its network adequacy review, which was paused in 2018, evaluating Qualified Health Plans (QHPs) for compliance with quantitative standards based on time and distance standards starting plan year (PY) 2023. As mentioned before, narrow networks are common in the Individual market. Many health plans can become noncompliant with their current network configuration — as of August 2022, CMS identified 243 out 375 issuers that were not in compliance with network adequacy standards as part of the agency's certification review of QHPs for PY 2023, either out of errors in completing the paperwork or actual noncompliance.³¹ To stay compliant, many plans need to rapidly broaden their networks and contract with more providers, which will highly likely drive the unit cost up.

Setting network adequacy aside, for 2024, all of the health plans regarded health equity as having a neutral or low impact on the medical cost trend. At this stage, most plans are gathering data and forming necessary analyses to come up with actionable plans to address the disparities in health and health care and have not factored health equity into their cost of care models with respect to shifts in near-term utilization pattern changes nor long-term population health impact.

Centers for Medicare and Medicaid (CMS) Health Plan and Hospital Price Transparency Rule

Starting January 1, 2021, hospitals have been required by CMS to provide clear, accessible pricing information online, including a comprehensive machine-readable file listing gross charges, discounted cash prices and charges negotiated between the hospital and third-party payers for all the items and services provided. In July 2022, the rule was extended to include both plans and Issuers as well.³²

In theory, the implementation of the Price Transparency Rule would expand visibility into unit prices and have wide implications for all stakeholders, including both hospitals and payers. On the one hand, hospitals could analyze the price transparency data to identify services where their charges are low relative to the market, or payers that are more generous in their reimbursements for competitor hospitals, and demand greater price increases for these services or with these payers in future contract negotiations. On the other hand, payers could similarly leverage price transparency data to improve their contracted prices as related to high-cost services or hospitals.³³

Nevertheless, in the short term, the utility of price transparency data could be limited given several practical issues. Data accuracy is one concern. One plan reported that it found that the prices published by the hospitals could not be reconciled with the contracted prices per their own database. In addition, published in various formats, machine-readable files require data analytics efforts to be transformed and merged into a meaningful dataset.

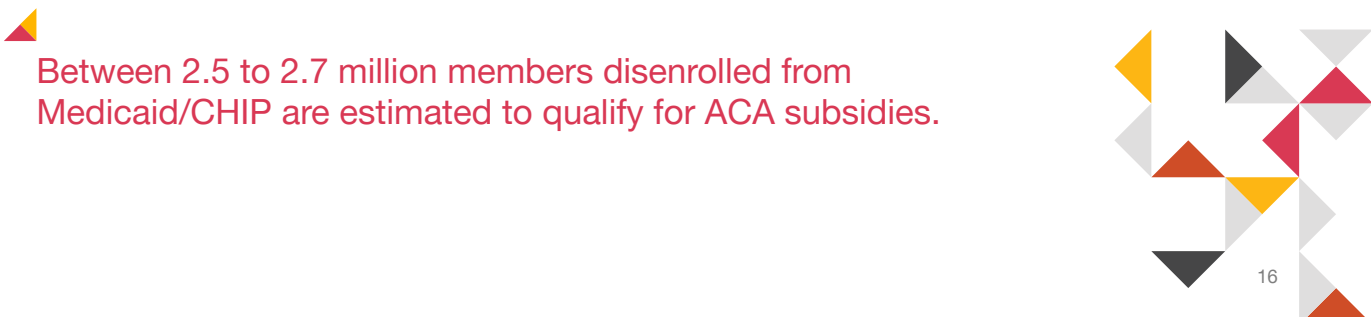
Overall, 75% of the plans surveyed deemed the impact of the Price Transparency Rule on 2024 medical cost trend to be neutral or immaterial mainly given the immaturity of the data. In the long run, plans could see both upward and downward pressures during the contract negotiation (for example, price increases demanded by low-paid providers and price control on high-cost providers). The extent to which more transparency will shift the balance of power in negotiations, which currently favor providers and payers with higher market share and in less competitive markets, remains to be seen.

Medicaid redetermination

In response to the public health crisis, Congress passed the Families First Coronavirus Response Act in 2020, which prohibits state Medicaid agencies from disenrolling people unless they specifically request it. The Kaiser Family Foundation reported that, as a result, enrollment in Medicaid and Children’s Health Insurance Program (CHIP) has grown by 21.9 million to nearly 93.0 million from February 2020 to January 2023.³⁴ This continuous enrollment provision ended on March 31, 2023, after which states have 12 months to initiate redeterminations of Medicaid and CHIP eligibility for all enrollees and two additional months (14 months total) to complete all pending actions.

The HHS projects the unwinding of the continuous enrollment provision to result in 15 million people losing Medicaid/CHIP coverage.³⁵ Specifically, among the disenrolled, 6.8 million are still eligible for Medicaid/CHIP but lost coverage due to administrative churning (they will not qualify for ACA subsidies³⁶). For the remaining 8.2 million who are no longer Medicaid/CHIP eligible, HHS estimates 3.6 million to obtain employer-sponsored insurance (ESI), 2.7 million to qualify for ACA premium tax credits (PTC), including 1.7 million also eligible for zero-premium Individual plans under the provisions of the ARP and IRA. A separate study by the Urban Institute estimates 18 million people losing Medicaid/CHIP coverage, of which 2.5 million will be eligible for PTCs.³⁷

A consensus among health plans is that the impact of Medicaid redetermination is likely to be felt predominantly in the Individual market. Disenrollees who obtain employer-sponsored insurance can either be previously double-covered by Medicaid/CHIP and ESI or obtain ESI through new employment as unemployment recovers back to the pre-pandemic level. It is uncertain how many will eventually be covered by small or Large Group plans, but these new members are not expected to significantly alter the risk pool of Group plans. On the Individual side, among the 2 million to 3 million disenrollees who become eligible for PTCs, not all of them will enroll in Individual plans. Many health plans expect a selection effect in which those who choose to enroll in Individual plans tend to have higher risk. Nevertheless, per the HHS projection, the Medicaid/CHIP disenrollees are much younger than the existing Individual market population and thus potentially lower risk.³⁸ Overall, the net impact of Medicaid redetermination could be an inflator or deflator, as believed by most health plans, and 80% of the plans indicated the impact to be neutral or low on the 2024 medical cost trend.



About this research

Each year, PwC's Health Research Institute (HRI) projects the growth of employer medical costs in the coming year and identifies the leading trend drivers. Health insurance companies use the medical cost trend to help set premiums by estimating what this year's health plan will cost next year. In turn, employers use the information to make adjustments to benefit plan design to help offset health insurance cost increases. The report identifies and explains what it refers to as "inflators" and "deflators" to describe why and how the healthcare spending growth rate is affected.

This forward-looking report is based on the best available information through June 2023. HRI conducted 21 surveys and 12 interviews from April through May 2023 with health plan actuaries whose companies cover nearly 100 million employer-sponsored large and small group members and 10 million ACA marketplace members. Participants were asked about their trend experience for 2022, and trend estimates for 2023-24, and the factors driving those trends.

Results from the surveys and interviews were aggregated using a weighted average approach based on the number of self-reported lives in the survey. Results for Group and Individual trend were not aggregated for any purposes or results during this process.



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Slide 1/Main Trend Chart:

Source: PwC Health Research Institute medical cost trends, 2009-2024

Slide 2/Medical Inflation/ wages:

Source: Bureau of Labor Statistics Consumer Price Index, PwC Analysis

Slide 3/Employment:

Source: Bureau of Labor Statistics Employment Cost Index, PwC Analysis

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Slide 4/Physician acquisitions:

Source: Physician Advocacy Institute report on COVID-19's impact on acquisitions of physician practices and physician employment 2019-2021

Footnote this alongside the text above ->

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Slide 5/Median price of newly marketed drugs:

Source: Article on Trends in Prescription Drug Launch Prices, 2008-2021 published in The Journal of the American Medical Association

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Slide 6/ Number of drugs with price increases:

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Slide 8/Biosimilars chart timeline:

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Slide 9/Both knee charts:

Source: Strata National Patient and Procedure Volume Tracker
Footnote this alongside the text above ->

"The National Patient and Procedure Volume Tracker," StrataSphere, June 2023.
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www.pwc.com

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description	2018 (1)	2019	2020	2021	2022	Constant Dollar Five-Year Average Cost Per Employee	2022 Average Employees	Constant Dollar 2022 Costs	Actual 2022 Costs	Difference	Percent Expensed	Constant Dollar Adjustment
									Col.(g) X Col.(h)	Col.(f), L.4	Col.(i) - Col.(j)		Col. (k) X Col.(l)
1	Medical Costs	\$63,824	\$65,627	\$63,551	\$78,455	\$77,234							
2	Dental Costs	3,827	4,276	3,203	5,319	5,307							
3	Vision Costs	526	516	448	510	457							
4	SubTotal Active Healthcare Costs	68,178	70,419	67,201	84,284	82,998							
5	Average Annual Number of Employees	6,795	6,896	6,848	6,751	6,697							
6	Cost/Employee	\$10.034	\$10.211	\$9.813	\$12.485	\$12.393							
7													
8		10.034											
9	2019 PwC Actual Annual Healthcare Trend	5.7%											
10		10.606	10.211										
11	2020 PwC Actual Annual Healthcare Trend	5.5%	5.5%										
12		11.190	10.773	9.813									
13	2021 PwC Actual Annual Healthcare Trend	6.0%	6.0%	6.0%									
14		11.861	11.419	10.402	12.485								
15	2022 PwC Actual Annual Healthcare Trend	4.0%	4.0%	4.0%	4.0%								
16		\$12.335	\$11.876	\$10.818	\$12.985	\$12.393	\$12.081	6,697	\$80,911	\$82,998	(\$2,087)	60.4%	(\$1,260)
17													
18											Medical Costs		(\$1,173)
19	(1) Excludes one-time credit recognized in 2018.										Dental Costs		(81)
20											Vision Costs		(7)
21											Total		(\$1,260)
22													
23	(2) Derivation of Annual Healthcare Trend:	2019	2020	2021	2022 Est.								
24	PwC Actual Annual Healthcare Trend	5.7%	6.0%	7.0%	5.5%								
25	Wellness Adjustment	0.0%	(0.5%)	(1.0%)	(1.5%)								
26	Adjusted PWC Annual Healthcare Trend	5.7%	5.5%	6.0%	4.0%								

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Pension Cost - Qualified
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C5.12.1
 Witness: M. A. Fix
 Page: 1 of 1

		(a)	(b)	(c)	(d)
		Pension Cost - Qualified			
Line No.	Description	Historical Period Ending 12/31/22	Projected Adjustments	Projected Period Ending 12/31/25	
1	Cost Components:				
2	Service cost	71,546	(30,536)	41,010	
3	Non-Service Costs				
4	Interest cost	123,405	33,561	156,966	
5	Expected return on assets	(248,709)	35,531	(213,178)	
6	Amortization:				
7	Net (Gain)/Loss	81,126	(10,993)	70,133	
8	Prior service cost	(1,179)	241	(938)	
9	Total Non-Service Costs	(45,357)	58,340	12,983	
10	Net ASC 715-30 (SFAS 87) cost	26,189	27,804	53,993	
11	One-time cost	64,798	(64,798)	-	
12	Net ASC 715-30 (SFAS 87) after one-time cost	90,987	(36,994)	53,993	
13	<u>Reconcile Cost to Expense</u>				
14	Expense before capitalization & transfers	90,987	(36,994)	53,993	
15	Adjustments:				
16	Transfers	(435)	(1,260)	(1,695)	
17	Capitalization (Service Cost only effective 2018)	(33,359)	17,944	(15,416)	
18	Capitalization - Non-Service Costs to Reg (Asset)	(5,419)	810	(4,609)	
19	Subtotal Pension Expense	51,774	(19,501)	32,273	
20	Pension Regulatory Deferral	(39,527)	7,254	(32,273)	
21	Expense amount per Exhibit A-13 C5.11	12,247	(12,247)	-	

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Other Post Employment Benefits (OPEB)
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C5.12.2
 Witness: J. K. Hooper
 Page: 1 of 1

		(a)	(b)	(c)	(d)
		Other Post Employment Benefits (OPEB)			
Line No.	Description	Historical Period Ending 12/31/22	Projected Adjustments	Projected Period Ending 12/31/25	
1	Cost Components:				
2	Service cost	20,456	(8,307)	12,149	
3	Non-Service Costs				
4	Interest cost	36,687	12,629	49,316	
5	Expected return on assets	(84,742)	8,758	(75,984)	
6	Amortization:				
7	Net (Gain)/Loss	4,659	(4,659)	-	
8	Prior service cost	(13,721)	13,781	60	
9	Total Non-Service Costs	(57,117)	30,509	(26,608)	
10	Net ASC 715-60 (SFAS 106) Cost	(36,661)	22,202	(14,459)	
11	<u>Reconcile Cost to Expense</u>				
12	Expense before capitalization & transfers	(36,661)	22,202	(14,459)	
13	Adjustments:				
14	Transfers	(68)	(3)	(71)	
15	Capitalization (Service Cost only effective 2018)	(7,412)	2,878	(4,534)	
16	Capitalization - Non-Service Costs to Reg Liability	22,276	(11,606)	10,670	
17	Subtotal OPEB Expense	(21,865)	13,470	(8,395)	
18	OPEB Regulatory Deferral	21,865	(13,470)	8,395	
19	Amortization of OPEB Regulatory Liability	-	(18,300)	(18,300)	
20	OPEB Expense per Exhibit A-13 C5.11 (Line 3)	-	(18,300)	(18,300)	

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Information Technology
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.13
Witness: P. Sharma
Page: 1 of 2

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		1/1/22 - 12/31/22 Historical Test Period	1/1/23 - 12/31/23 Inflation 1/	1/1/24 - 12/31/24 Inflation 1/	1/1/25 - 12/31/25 Inflation 1/	Other	Total Projected Adjustments	Projected Test Period
			Projected Adjustments					
1	Information Technology						sum (c) thru (f)	(b) + (g)
2	Operation							
3	Base Operate (primarily labor costs)	39,423	1,262	1,180	1,214	-	3,655	43,079
4	License Management & Maintenance	47,440	1,518	1,420	1,461	-	4,399	51,839
5	Project Cost to Achieve	19,556	626	585	602	-	1,813	21,369
6	Other - Dell Finance Lease	5,689	182	170	175	-	528	6,217
7	A&G Capitalized	(36,836)	(1,179)	(1,102)	(1,134)	-	(3,416)	(40,252)
8	Total Operation & Maintenance Expense	75,272	2,409	2,253	2,318	-	6,980	82,251

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Information Technology
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.13
Witness: P. Sharma
Page: 2 of 2

	<u>1/1/23 - 12/31/23</u>	<u>1/1/24 - 12/31/24</u>	<u>1/1/25 - 12/31/25</u>
1/ Annual Inflation Rate	3.20%	2.90%	2.90%
No. of Months in Period	<u>12</u>	<u>12</u>	<u>12</u>
Pro-rated Inflation Rate	3.20%	2.90%	2.90%

Case No. U-21534
Exhibit: A-13
Schedule: C5.14

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Michigan Public Service Commission
DTE Electric Company
Inflation Factors

Case No.: U-21534
Exhibit: A-13
Schedule: C5.15
Witness: T. M. Uzenski
Page: 1 of 1

Line No.	(a) Description	(b) CY 2023	(c) CY 2024	(d) CY 2025	(e) Reference
1	<u>Labor Inflation</u>				
2	Wage Inflation Rate	3.0%	3.0%	3.0%	Sponsored by Witness Cooper
3	Pro-ration	48.7%	48.7%	48.7%	Workpaper TMU-15
4	Labor Inflation Component	1.5%	1.5%	1.5%	Line 2 x Line 3
5	<u>Contractors Inflation</u>				
6	Wage Inflation Rate	3.0%	3.0%	3.0%	Line 2
7	Pro-ration	35.3%	35.3%	35.3%	Workpaper TMU-15
8	Contractors Inflation Component	1.1%	1.1%	1.1%	Line 6 x Line 7
9	<u>Non-Labor Inflation</u>				
10	CPI-U Rate	4.1%	2.4%	2.2%	S&P/IHS Markit - U.S. Economic Outlook: October 2023
11	Pro-ration	16.0%	16.0%	16.0%	Workpaper TMU-15
12	Non-Labor Inflation Component	0.7%	0.4%	0.4%	Line 10 x Line 11
13	Composite Inflation Rate	3.20%	2.90%	2.90%	
14	No. of Months to Pro-rate	12	12	12	
15	Rate Applied in Test Period	3.20%	2.90%	2.90%	
16	Applicable Period Beginning	1/1/23 -	1/1/24 -	1/1/25 -	
17	Applicable Period Ending	12/31/23	12/31/24	12/31/25	

Michigan Public Service Commission
DTE Electric Company
Nuclear Power Generation
Projected PERC O&M Expenditures
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C5.16
 Witness: J. C. Davis
 Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	CY 2022 - A	CY 2023	CY 2024	CY 2025
1	Refueling outage planning, readiness and demobilization	5,496	3,755	2,665	4,902
2	Desludge - Torus	4,126	-	993	-
3	Reactor feed pump turbine (RFPT) inspections	2,333	674	5,786	-
4	Residual Heat Removal Heat Exchanger (RHR HX) coating	2,091	74	2,748	-
5	Hydraulic control unit (HCU) preventative maintenance	1,833	96	2,010	-
6	Force-on-force (FOF) inspections	623	47	-	660
7	Integrated Leak Rate Test (ILRT)	427	-	-	-
8	High energy line break (HELB) analysis	413	856	-	-
9	Emergency Core Cooling System (ECCS) suction strainer	331	186	-	-
10	Switchyard modification	144	-	-	-
11	24-Month operating cycle	98	-	-	-
12	Switchyard Outage 22-01	65	-	-	-
13	Independent Spent Fuel Storage Installation (ISFSI) fuel characterization	22	-	-	-
14	Spent Fuel Pool (SFP) cleanup campaign	-	1,700	-	-
15	Adopt risk informed completion times (TSTF-505)	-	744	-	304
16	Reactor Recirculation System (RRS) Sample Line Outage 23-01	-	262	-	-
17	Core shroud inspections	-	254	2,957	-
18	Rail tie replacements	-	209	-	-
19	Thermal recombiner inplace abandonment	-	50	-	136
20	Feed water heater (FWH) bridging strategy	-	-	2,836	-
21	Circulating Water Pump (CWP) refurbishments	-	-	1,220	643
22	Implementation of 10 CFR 50.69: Categorization and Alternative Treatment	-	-	543	865
23	Reactor Recirculation System (RRS) sample line modification	-	133	536	-
24	Critical digital asset (CDA) optimization	-	-	314	-
25	High Pressure Turbine (HPT) inspections	-	-	-	597
26	Dredge General Service Water	-	-	-	351
27	License renewal implementation inspections	-	-	-	126
28	Independent Spent Fuel Storage Installation (ISFSI) campaign	(32)	(256)	-	-
29	Balance of projects (<\$100k)	88	100	-	-
30	Total PERC O&M Expenditures	18,058	8,883	22,608	8,584

Michigan Public Service Commission
DTE Electric Company
PERC Regulatory Asset Amortization
Projected Test Period - 12 Months Ending December 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C5.17
Witness: T. M. Uzenski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	Actual CY 2022	Projected CY 2023	Projected CY 2024	Projected CY 2025	Reference		
1	PERC Deferral (Note 1)							
2	PERC Expenses	18,058	8,883	22,608	8,584	Sponsored by Witness Davis (Exh.A-13, C5.16)		
3	PERC Base Amount	15,000	15,000	15,000	15,000			
4	PERC Regulatory Asset Deferral	3,058	(6,117)	7,608	(6,416)			

		Amortization Expense							
5		Deferral by	Actual	Projected	Projected	Projected	Test Period	Amortization Period	
6	PERC Amortization (Note 2)	Vintage Year	CY 2022	CY 2023	CY 2024	CY 2025	Amortization	Beginning	Ending
7	2017 Vintage	22,136	4,428	-	-	-	-	1/1/2018	12/31/2022
8	2018 Vintage	25,646	5,129	5,129	-	-	-	1/1/2019	12/31/2023
9	2019 Vintage	13,838	2,755	2,768	2,768	-	-	1/1/2020	12/31/2024
10	2020 Vintage	19,818	3,963	3,964	3,964	3,964	3,964	1/1/2021	12/31/2025
11	2021 Vintage	-	-	-	-	-	-	1/1/2022	12/31/2026
12	2022 Vintage	3,058	-	612	612	612	612	1/1/2023	12/31/2027
13	2023 Vintage (Projected)	(6,117)	-	-	(1,223)	(1,223)	(1,223)	1/1/2024	12/31/2028
14	2024 Vintage (Projected)	7,608	-	-	-	1,522	1,522	1/1/2025	12/31/2029
15	Amortization Expense		16,275	12,472	6,119	4,873	4,873		

1/ Authorization to defer PERC project costs in excess of \$4.9 million base to a regulatory asset per order in Case No. U-18014.

Base level increased to \$15 million effective 5/1/2020 pursuant to order in Case No. U-20561

2/ Deferred costs are amortized over a five-year period

Michigan Public Service Commission
DTE Electric Company
Projected Depreciation and Amortization Expense
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C6
Witness: T. M. Uzenski
Page: 1 of 2

Line No.	(a) Description	(b)	(c)	(d)	(e)
		Adj. Historical 12 mos. ended 12/31/22	Projection Adjustments	Test 12 mos. ending 12/31/25	Reference
1	<u>Depreciation & Amort (403-407, 411.1)</u>				
2	Plant DD&A (403, 403.1)	923,999	91,865	1,015,864	Exhibit A-13 C6 page 2, line 15 , col. (k)
3	Software Amortization / Intangible (405)	<u>124,240</u>	<u>(25,569)</u>	<u>98,671</u>	Exhibit A-13 C6 page 2, line 23 , col. (k)
4	Subtotal Plant Depr. & Amortization	1,048,239	66,296	1,114,535	Exhibit A-13 C6 page 2, line 25 , col. (k)
5	Amortization of COL (405)	4,893	0	4,893	
6	Amort. of Utility Plant Acq. Adj. (406)	5,791	(0)	5,791	
7	AFUDC-Reg Asset Amort (407.3)	5	(5)	-	
8	Amortization of Monroe Regulatory Asset (407.3)	-	144,067	144,067	Exhibit A-12 B4.4, line 6
9	Amortization of Demand Response (407.4)	(706)	3,576	2,870	Regulatory Asset for 2019, 2020, and 2021 Demand Response
10	Amortization of Capitalized Pension (407.3)	883	(1,794)	(911)	Regulatory Asset for non-service costs per U-18255 Order
11	Amortization of Capitalized OPEB (407.4)	<u>(2,950)</u>	<u>(2,050)</u>	<u>(5,000)</u>	Regulatory Liability for non-service costs per U-18255 Order
12	Depreciation & Amortization	<u>1,056,155</u>	<u>210,090</u>	<u>1,266,245</u>	

Michigan Public Service Commission
DTE Electric Company
Projected Depreciation and Amortization Expense
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit No.: A-13
Schedule No.: C6
Witness: T. M. Uzenski
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description	Ending Plant Balance				Projected Simple Average		Annual Composite Depr. Rate 1/	Depreciation & Amortization Expense				
		Adj. Historical	Projected	Projected	Projected	Average Balance	Average Balance		Projected	Projected	Total	Historical	Projection
		12/31/2022 Balance	12/31/2023 Balance	12/31/2024 Balance	12/31/2025 Balance	12/31/2023 - 12/31/2025	12/31/2024 - 12/31/2025		0 mo. end 12/31/2025	12 mo. end 12/31/2025	12 mo. end 12/31/2025	12 mo. end 12/31/2022	Change
						(col. (c)+(d)) ÷ 2	(col. (d)+(e)) ÷ 2		col. (f) x (h)	col. (g) x (h)	col. (i) + (j)		col. (k) - (l)
1	Depreciable Plant:								÷ 12 x 0 months	÷ 12 x 12 months			
2	Production Plant, Steam - Monroe	4,253,693	4,403,629	1,092,000	1,064,309	2,747,814	1,078,154	3.20%	-	34,527	34,527	137,491	(102,964)
2a	Monroe - Life Component							2.82%	-	30,388	30,388		
2b	Monroe - Removal Component							0.38%	-	4,139	4,139		
3	Production Plant, Steam - Other	2,403,161	2,450,989	2,551,819	2,485,184	2,501,404	2,518,502	3.24%	-	81,604	81,604	87,651	(6,047)
4	Production Plant, Nuclear	1,689,937	1,730,937	1,867,581	1,894,359	1,799,259	1,880,970	4.26%	-	80,181	80,181	67,073	13,108
5	Production Plant, Hydraulic	613,585	621,433	626,308	632,906	623,871	629,607	2.65%	-	16,661	16,661	15,240	1,421
6	Production Plant, Other	1,666,911	1,691,242	1,828,413	1,857,587	1,759,828	1,843,000	2.17%	-	39,903	39,903	25,037	14,866
7	Production Plant, MERC	98,067	99,449	100,546	101,527	99,997	101,036	4.05%	-	4,092	4,092	3,952	140
8	Transmission Plant	49,851	44,935	40,019	35,103	42,477	37,561	2.37%	-	890	890	1,934	(1,044)
9	Distribution Plant	11,004,185	12,031,558	13,112,345	14,434,117	12,571,952	13,773,231	4.11%	-	566,019	566,019	434,356	131,662
10	Distribution Plant, AMI	455,679	455,679	455,679	455,679	455,679	455,679	5.04%	-	22,966	22,966	22,292	674
11	General Plant, Depreciable	835,823	911,167	1,024,650	1,139,346	967,908	1,081,998	7.56%	-	81,837	81,837	61,750	20,087
12	General Plant, Amortizable	662,654	628,472	607,190	579,635	617,831	593,413	8.53%	-	50,589	50,589	52,657	(2,068)
13	General Plant, Amortizable 5 Yr.	66,594	115,110	156,980	208,965	136,045	182,972	20.00%	-	36,594	36,594	14,564	22,031
14	Other Plant, Composite	-	-	-	-	-	-	4.44%	-	-	-	-	-
15	Total Depreciable Plant	23,800,141	25,184,600	23,463,531	24,888,716	24,324,065	24,176,124		-	1,015,864	1,015,864	923,999	91,865
16	Intangible Plant, 3 year	118,886	102,223	41,072	(11,333)	71,647	14,870	33.33%	-	4,957	4,957	33,698	(28,741)
17	Intangible Plant, 4 year	241	67	(0)	(0)	33	(0)	25.00%	-	(0)	(0)	68	(68)
18	Intangible Plant, 5 year	366,899	390,532	398,496	356,584	394,514	377,540	20.00%	-	75,508	75,508	74,994	514
19	Intangible Plant, 7 year	-	-	-	-	-	-	14.29%	-	-	-	-	-
20	Intangible Plant, 15 year	200,468	224,395	230,795	246,185	227,595	238,490	6.67%	-	15,899	15,899	15,137	762
21	Intangible Plant, 20 year	-	-	-	72,910	-	36,455	5.00%	-	1,823	1,823	-	1,823
22	Intangible Plant, 30 year	14,545	14,545	14,545	14,545	14,545	14,545	3.33%	-	485	485	343	141
23	Total Intangible Plant	701,039	731,761	684,908	678,891	708,334	681,899		-	98,671	98,671	124,240	(25,569)
24	Land/Land Rights	82,883	78,925	78,925	78,925	78,925	78,925		-	-	-	-	-
25	Total Plant	24,584,064	25,995,286	24,227,364	25,646,532	25,111,325	24,936,948		-	1,114,535	1,114,535	1,048,239	66,296
26	Reconciliation of Plant Adjustments:												
27	Beginning Balance		24,584,064	25,995,286	24,227,364								
28	Plant Unitization		1,777,192	2,052,946	1,920,796								
29	Plant Retirements		(365,970)	(398,818)	(574,538)								
30	Relcass Fermi License from Future Use				72,910								
31	Reclass Monroe to Regulatory Asset		-	(3,422,049)	-								
32	Net Plant Adjustments		1,411,222	(1,767,922)	1,419,167								
33	Ending Balance		25,995,286	24,227,364	25,646,532								

1/ Reflects composite depreciation rates based on Case No. U-18150 ordered depreciation rates (see Workpaper TMU-16)

Michigan Public Service Commission
DTE Electric Company
Projected General Taxes - Other
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C7
Witness: S. L. Wisniewski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Rate Case Adjustments 1/								
Line No.	Description	Historical Test Period 12/31/2022	Add MERC	Eliminate Surcharge Programs	Adjusted Historical 12/31/2022	2022 Inflation	2023 Inflation	2024 Inflation	Projection Adjustment	Projected Test Period
1	Property Taxes	286,558	975	(21,634)	265,899				62,874	328,772 2/
2	Payroll Taxes	36,678	169	(863)	35,984	1,080	1,112	1,145	-	39,321 3/
3	Public Utility Assessment	12,948	-	-	12,948	-	-	-	668	13,616 4/
4	Other	243	-	-	243	-	-	-	-	243
5	Other General Taxes	49,869	169	(863)	49,175	1,080	1,112	1,145	668	53,180
6	Total Projected General Taxes	336,427	1,144	(22,497)	315,074	1,080	1,112	1,145	63,542	381,953

1/ Rate Case Adjustments to add MERC and eliminate Surcharge Programs sponsored by Witness Uzenski on Exhibit A-3 C1.1

2/ Projected Property Taxes are carried from Line 23, Exhibit A-13, Schedule C7.1

3/ Projected Payroll Taxes represent historical payroll tax expense plus inflation as directed by Witness Uzenski (inflation rate carried from Exhibit A-13, Schedule C5.15)

4/ Projected Public Utility Assessment represents historical costs adjusted for increase in contributions to the Utility Customer Representation Fund as a result of Public Act 231 of 2023.

Annual Inflation Rate	3.00%	3.00%	3.00%
No. of Months in Period	12	12	12
Pro-rated Inflation Rate	3.00%	3.00%	3.00%

Michigan Public Service Commission
DTE Electric Company
Projected General Taxes - Property
Projected 12 Month Period Ending Dec. 31, 2025
(\$000's)

Case No.: U-21534
Exhibit: A-13
Schedule: C7.1
Witness: S. L. Wisniewski
Page: 1 of 1

Line No.	(a) Description	(b) Reference	(c) Amount	(d) %	(e) Expense
1	Property Tax Expense				
2	Calendar Year 2023				
3	2022 Tax Liability (2022-2023 expense)	WP-SLW-1	265,448	61%	161,923
4	2023 Tax Liability (2023-2024 expense)	WP-SLW-1	281,370	39%	109,734
5	DTE Electric Company	Line 3 + Line 4			271,658
6	MERC	Prior Year Liability			975
7	Total Property Tax Expense - CY 2023	Line 5 + Line 6			272,633
8	Calendar Year 2024				
9	2023 Tax Liability (2023-2024 expense)	WP-SLW-1	281,370	61%	171,636
10	2024 Tax Liability (2024-2025 expense)	Line 54	313,768	39%	122,370
11	DTE Electric Company	Line 9 + Line 10			294,005
12	MERC Expense	Line 6			975
13	Total Property Tax Expense - CY 2024	Line 11 + Line 12			294,980
14	Calendar Year 2025				
15	2024 Tax Liability (2024-2025 expense)	Line 54	313,768	61%	191,398
16	2025 Tax Liability (2025-2026 expense)	Line 56	349,741	39%	136,399
17	DTE Electric Company	Line 15 + Line 16			327,797
18	MERC Expense	Line 12			975
19	Total Property Tax Expense - CY 2025	Line 17 + Line 18			328,772
20	Projected Test Year				
21	Total Property Tax Expense - CY 2024	Line 13 + 12 x 0 months			-
22	Total Property Tax Expense - CY 2025	Line 19 + 12 x 12 months			328,772
23	Total Property Tax Expense for Projected Test Period				\$ 328,772

24	Property Tax Liability		2023 Cost	2024 Cost
25	Net Plant Additions	WP-SLW-1	1,556,936	1,797,635
26	Less Nontaxable Expenditures	WP-SLW-1	(437,948)	(459,740)
27	Total Plant Additions subject to property tax	Line 25 + Line 26	1,118,989	1,337,895
28	1st Year Multiplier	AVG STC Multiplier	96.00%	96.00%
29	True Cash Value - CY Activity	Line 27 x Line 28	1,074,229	1,284,379
30	Change in CWIP subject to property tax	WP-SLW-1	326,235	150,081
31	1st Year Multiplier	AVG STC Multiplier	50.00%	50.00%
32	True Cash Value - CWIP	Line 30 x Line 31	163,118	75,041
33	True Cash Value Total	Line 29 + Line 32	1,237,347	1,359,419
34			50.00%	50.00%
35	Taxable Value CY Additions = 50% of True Cash Value	Line 33 x Line 34	618,673	679,710
36				
37	Taxable Value of Real Property -- based on assets as of 12/31/2022	WP-SLW-1	669,671	669,671
38	Increase in Real Property Taxable Value	Col. (c), Line 41	n/a	33,484
39	Taxable Value of Real Property	Line 37 + Line 38	669,671	703,154
40	Inflation Rate Multiplier		5.00%	5.00%
41	Increase in Real Property Taxable Value	Line 39 x Line 40	33,484	35,158
42				
43	Taxable Value of Personal Property -- based on assets as of 12/31/2022	WP-SLW-1	4,801,353	4,801,353
44	Decrease in Personal Property Taxable Value	Col. (c), Line 48	n/a	(73,621)
45	Prior Year Taxable Value	Line 43 + Line 44	4,801,353	4,727,732
46	Annual Obsolescence multiplier	WP-SLW-1	1.5%	1.5%
47	Decrease in Property Tax Taxable Value	Line 45 x Line 46 x -1	(73,621)	(72,492)
48	Incremental Increase to Taxable Value	Line 35 + Line 41 + Line 47	578,536	642,375
49	Millage Rate		56.0	56.0
50	Increase in Property Tax Liability	Line 48 x Line 49 + 1000	32,398	35,973
51				
52	2023 Property Tax Liability	WP-SLW-1	281,370	
53	2024 - Increase in Property Tax Liability	Col. (c), Line 50	32,398	
54	2024 Property Tax Liability	Line 52 + Line 53	313,768	313,768
55	2025 - Increase in Property Tax Liability	Col. (e), Line 50		35,973
56	2025 Property Tax Liability	Line 54 + Line 55		349,741

Michigan Public Service Commission
DTE Electric Company
Projected Federal Income Tax
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C8
 Witness: S. L. Wisniewski
 Page: 1 of 2

Line No.	(a) Description	(b) Reference	(c) Projected Test Period
1	Net Operating Income	A-13, C1 Line 17	1,087,100
2	Interest Expense	A-13, C14, Line 3	(396,440)
3	Interest Synchronization	A-13, C15, Line 5	(667)
4	Net Income	Sum of Line 1 through 3	689,993
5	Current Federal Income Tax Expense		12,470
6	Deferred Federal Income Tax Expense		95,306
7	Total Federal Income Tax Expense	Line 5 + Line 6	107,776
8	Pre-Tax Income	Line 4 + Line 7	797,769
9	<u>Permanent Differences</u>		
10	ESOP		(9,700)
11	Parking Lot Disallowance		1,550
12	Meals and Entertainment		2,100
13	AFUDC Equity		(31,491)
14	Total Permanent Differences	Sum of Line 10 through 13	(37,541)
15	<u>Temporary Differences</u>		
16	Tree Trim Regulatory Asset/Liability and Amortization		(130,700)
17	Monroe Regulatory Asset/Liability and Amortization		144,067
18	Pension Regulatory Asset/Liability and Amortization		(37,793)
19	OPEB Regulatory Asset/Liability and Amortization		(4,236)
20	Other Regulatory Asset/Liability Deferral and Amortization		11,003
21	Pension Accrual		37,496
22	OPEB Accrual		(21,854)
23	Section 263A Adjustment		(30,000)
24	Property Tax		(52,444)
25	AFUDC Debt		(16,788)
26	Uniform Cost Cap Avoided Interest		39,252
27	Removal Costs		(299,686)
28	Book Depreciation		1,169,597
29	Tax Depreciation		(893,105)
30	Contributions in Aid of Construction		49,648
31	Repairs Allowance		(492,710)
32	FERMI 2 Outage Accrual and Expenses		17,000
33	Casualty Loss Deduction		(74,000)
34	Other Timing Differences		381
35	State and Local Deferred Taxes		61,127
36	Total Temporary Differences	Sum of Line 16 through 35	(523,745)
37	Total Permanent and Temporary Differences	Line 14 + Line 36	(561,286)

Michigan Public Service Commission
DTE Electric Company
Projected Federal Income Tax
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C8
 Witness: S. L. Wisniewski
 Page: 2 of 2

Line No.	(a) Description	(b) Reference	(c) Projected Test Period
38	Federal Taxable Income	Line 8 + Line 37	236,483
39	Net Operating Loss Generated (Utilized)		(177,103)
40	Federal Taxable Income after NOL	Line 38 + Line 39	59,380
41	Tax Rate		21%
42	Current Federal Income Tax Expense Before Tax Credits	Line 40 x Line 41	12,470
43	Prior Year Tax Credits Utilized		-
44	Current Federal Income Tax Expense After Tax Credits	Line 42 + Line 43	12,470
45	Deferred Federal Income Tax Expense	(Line 36 + Line 39) x 21%	147,178
46	Medicare Part D Subsidy Amortization		-
47	FAS 109 Amortization		1,764
48	Investment Tax Credit Amortization		(450)
49	TCJA Regulatory Liability Amortization		(50,186)
50	R & D Credit Carryforward		(3,000)
51	Prior Year Tax Credits Utilized		-
52	Total Deferred Federal Income Tax Expense	Sum of Line 45 through 51	95,306
53	Total Federal Income Tax Expense (to Exhibit A-13, Schedule C1)	Line 44 + Line 52	107,776

Michigan Public Service Commission
DTE Electric Company
Projected TCJA Regulatory Liability
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C8.1
Witness: S. L. Wisniewski
Page: 1 of 1

(a)		(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Description	General Rate Case Protected Plant	TRM Protected Plant	General Rate Case Unprotected Plant	General Rate Case Non-Plant	TRM Non-Plant	Total DTE Electric
1	Amortization Period	ARAM	ARAM	23	14	14	
2	TCJA Liability Before Gross Up						
3	DTE Electric Company in Total	(718,880)	(2,612)	(621,506)	(107,050)	40	(1,450,008)
4	Less: Non-Base Rate	108,621	-	-	(18,966)	-	89,656
5	Add: MERC	(2,792)	-	-	-	-	(2,792)
6	General Rate Case TCJA Regulatory Liability before gross up	(613,051)	(2,612)	(621,506)	(126,015)	40	(1,363,145)
7							
8	Amortization Schedule						
9	2019	(11,040)		(17,452)	(5,813)		(34,305)
10	2020	(23,589)		(27,022)	(9,001)		(59,612)
11	2021	(24,957)	(22)	(27,022)	(18,292)	3	(70,290)
12	January - November 2022	(19,793)	(20)	(24,770)	(92,909)	3	(137,490) 1/
13	December 2022	(1,799)	(2)	(2,252)	-	0	(4,053)
14	January - November 2023	(21,186)	(20)	(24,770)	-	3	(45,973)
15	December 2023	(1,926)	(2)	(2,252)	-	0	(4,179)
16	2024	(25,014)	(34)	(27,022)	-	3	(52,067)
17	2025	(23,132)	(35)	(27,022)	-	3	(50,186)
18	2026	(21,878)	(42)	(27,022)	-	3	(48,938)
19	2027	(19,777)	(42)	(27,022)	-	3	(46,837)
20	2028	(17,697)	(42)	(27,022)	-	3	(44,757)
21	2029	(18,396)	(42)	(27,022)	-	3	(45,457)
22	2030	(19,008)	(42)	(27,022)	-	3	(46,068)
23	2031	(21,586)	(42)	(27,022)	-	3	(48,646)
24	2032	(21,603)	(42)	(27,022)	-	3	(48,663)
25	2033	(20,250)	(42)	(27,022)	-	1	(47,313)
26	2034	(17,367)	(42)	(27,022)	-	-	(44,431)
27	2035	(17,911)	(42)	(27,022)	-	-	(44,975)
28	2036	(20,964)	(120)	(27,022)	-	-	(48,106)
29	2037	(23,141)	(159)	(27,022)	-	-	(50,323)
30	2038	(24,576)	(159)	(27,022)	-	-	(51,757)
31	2039	(24,020)	(159)	(27,022)	-	-	(51,201)
32	2040	(23,106)	(159)	(27,022)	-	-	(50,287)
33	2041	(22,293)	(159)	(27,022)	-	-	(49,475)
34	2042	(18,853)	(159)	(9,570)	-	-	(28,583)
35							
36	Amortization beyond 2042	(108,188)	(983)	-	(0)	-	(109,171)
37	Total Amortization	(613,051)	(2,612)	(621,506)	(126,015)	40	(1,363,145)

Test Period
(01/01/2025 - 12/13/2025)
-
(50,186)
(50,186)

1/ Non-Plant acceleration for General Rate Case is in accordance with the U-20835 Order.

Michigan Public Service Commission
DTE Electric Company
Projected State Income Tax
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C9
 Witness: S. L. Wisniewski
 Page: 1 of 1

Line No.	(a) Description	(b) Reference	(c) Projected Test Period
1	Federal Taxable Income	Exh. A-13, Sch. C8, Line 38	236,483
2	Depreciation Adjustment		(121,579)
3	Taxes Based on Income		286
4	Michigan Taxable Income	Sum of Line 1 through 3	115,190
5	MI Apportionment %		98%
6	Apportioned Michigan Corporate Income Tax Base	Line 4 x Line 5	112,886
7	MCIT Business Loss Generated/(Utilized)		(112,886)
8	Apportioned MCIT Tax Base after Business Loss	Line 6 + Line 7	0
9	Tax Rate		6%
10	Current Michigan Corporate Income Tax	Line 8 x Line 9	0
11	Deferred Michigan Corporate Income Tax		48,312
12	Amortization of MCIT Miscellaneous Deferred Debit		10,062
13	Total Deferred Michigan Corporate Income Tax		58,374
14	Total Michigan Corporate Income Tax	Line 10 + Line 13	58,374
15	<u>State & Local Tax Carried to Exhibit A-13, Schedule C1</u>		
16	State Income Tax	Line 14	58,374
17	Local Income Tax	Exh. A-13, Sch. C10	3,039
18	State & Local Income Tax Expense excluding Ratemaking Adj.	Line 16 + Line 17	61,413

Michigan Public Service Commission
DTE Electric Company
Projected Local Income Tax
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
Exhibit: A-13
Schedule: C10
Witness: S. L. Wisniewski
Page: 1 of 1

(a)		(b)	(c)
Line No.	Description	Reference	Projected Test Period
1	Federal Taxable Income	A-13, C8 Line 38	236,483
2	Local Taxes Based on Income	Line 7	286
3	Municipal Taxable Income	Sum of Line 1 through 2	236,769
4	Municipal Net Operating Loss Generated(Utilized)		(150,001)
5	Municipal Income Tax Base	Line 3 + Line 4	86,768
6	Tax Rate		0.33%
7	Current Municipal Income Tax Expense	Line 5 x Line 6	286
8	Deferred Municipal Income Tax Expense		2,232
9	Amortization of City of Detroit Miscellaneous Deferred Debit		520
10	Total Deferred Municipal Income Tax Expense	Line 8 + Line 9	2,752
11	Total Municipal Income Tax Expense	Line 7 + Line 10	3,039

Michigan Public Service Commission
DTE Electric Company
Allowance for Funds Used During Construction (AFUDC)
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C11
 Witness: T. M. Uzenski
 Page: 1 of 1

(a)		(b)	(c)	(d)
		Adjusted Historical 12 mos. ended	Projected 12 mos. ending	
Line No.	Description	12/31/2022	12/31/2025	Reference
1	Energy Supply	6,058	21,023	Exh A-12, Sch B5.1 Page 8
2	Nuclear Generation	10,780	13,118	Exh A-12, Sch B5.3 Page 5
3	Distribution Operations	13,862	13,816	Exh A-12, Sch B5.4 Page 10
4	Information Technology	4,902	3,268	Exh A-12, Sch B5.7 Page 3
5	Corporate Staff	1,870	1,795	Exh A-12, Sch B5.8 Page 2
6	Total AFUDC before Adjustment	37,473	53,021	
7	Offset Return on AFUDC in CWIP		2,948	Exh A-13, Sch C11.1
8	Total AFUDC	<u>\$ 37,473</u>	<u>\$ 55,969</u>	
9	Per Income Statement (1):			
10	Equity AFUDC (419.1)	26,247	39,182	
11	Debt AFUDC (432)	11,225	16,788	
12	Total AFUDC	<u>\$ 37,473</u>	<u>\$ 55,969</u>	
13	AFUDC Rate:			
14	Equity AFUDC Rate	3.933%	3.893%	
15	Debt AFUDC Rate	<u>1.484%</u>	<u>1.668%</u>	
16		5.417%	5.561%	
17	Rate Order in Effect	/U-20836	U-21297	

Michigan Public Service Commission
DTE Electric Company
AFUDC Ratemaking Adjustment 1/
Projected 12 Month Period Ending December 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C11.1
 Witness: T. M. Uzenski
 Page: 1 of 1

(a)		(b)	(c)
Line		Projected	
No.	Description	12 mos. ending	Reference
		12/31/2025	
1	Projected AFUDC - embedded in CWIP	53,021	Exhibit A-13 C11, col. (c), Line 12
2	Rate Base Impact	53,021	2/
3	Authorized Rate of Return	5.56%	Exhibit A-13 C11, col. (c), Line 16
4	Return on AFUDC embedded in CWIP	2,948	Line 2 x Line 3

1/ AFUDC adjustment to net operating income to offset AFUDC included in CWIP per Order in Case Nos. U-20162 and U-20561.

2/ Although rate base is calculated based on a simple average, the full year amount of AFUDC is a reasonable estimate of the impact on rate base assuming the beginning CWIP balance has some embedded AFUDC.

Michigan Public Service Commission
DTE Electric Company
Projected Amortization of the Loss on Reacquired Debt
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
 Exhibit No.: A-13
 Schedule No.: C12
 Witness: T. M. Uzenski
 Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)
			Historical For the Year Ended	Projection	Projected For the Year
Line No.	Description	Account No.	12/31/2022	Adjustments	Ending 12/31/2025
1	Amortization of Loss on Reacquired Debt, DTE Electric	428.1	3,310	(1,066)	2,244
2	Amortization of Loss on Reacquired Debt, MERC 1/	428.1	-	-	-
3	Amortization of Loss on Reacquired Debt		<u>3,310</u>	<u>(1,066)</u>	<u>2,244</u>

1/ MERC debt matured August 2021

Michigan Public Service Commission
DTE Electric Company
Projected Other (Income) / Deductions
Projected 12 Month Period Ending Dec. 31, 2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C13
 Witness: T. M. Uzenski
 Page: 1 of 1

(a)		(b)	(c)	(d)
		Historical For the Year		Projected For the Year
Line		Ended	Projection	Ending
No.	Description	12/31/2022	Adjustments	12/31/2025
1	Asset (Gains)/Losses	-	-	-
2	Other (Income) and Deductions	(8,525)	-	(8,525)
3	Interest on Customer Deposits	1,729	-	1,729
4	Net Other (Income) / Deductions	(6,796)	-	(6,796)
		Exhibit.A-3,C1 col. (e), line 10		Exhibit.A-13,C1 col. (e), line 10

Michigan Public Service Commission
DTE Electric Company
Projected Tax Effect of Interest Allowed in Ratemaking Formula
12 Months Ended 12/31/2022 and 12/31/2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C14
 Witness: K. M. Vangilder
 Page: 1 of 1

Line No.	(a) Description	(b) Historical 12/31/2022	(c) Projected 12/31/2025	(d) Source
1	Rate Base	\$ 20,116,777	\$ 22,107,989	Exh.A-12, Sch. B1
2	Weighted Cost of Debt (1)	<u>1.53%</u>	<u>1.79%</u>	Exh.A-14, Sch. D1
3	Interest Allowed in Ratemaking Formula	\$ 307,465	\$ 396,440	Line 1 x Line 2
4	Interest Deduction included in Recorded Income Tax Accruals	<u>\$ 368,282</u>	<u>\$ 386,873</u>	WP-KMV-3
5	Increase / (Decrease) in Interest Deduction	\$ (60,817)	\$ 9,567	Line 3 - Line 4
6	Composite State and Municipal Income Tax Rate	6.21%	6.21%	Exh. A-13, Sch. C2
7	Effect on State and Municipal Income Tax Expense	<u>\$ 3,777</u>	<u>\$ (594)</u>	(Line 5 x Line 6) x -1
8	Effect on Federal Taxable Income	\$ 57,041	\$ (8,973)	(Line 5 + Line 7) x -1
9	Federal Income Tax Rate	<u>21.00%</u>	<u>21.00%</u>	Exh. A-13, Sch. C2
10	Effect on Federal Income Tax Expense	<u>\$ 11,979</u>	<u>\$ (1,884)</u>	Line 8 x Line 9
11	Total Tax Effect on Net Operating Income	<u><u>\$ (15,755)</u></u>	<u><u>\$ 2,478</u></u>	(Line 7 + Line 10) x -1

(1) Includes Short and Long-Term Interest

Michigan Public Service Commission
DTE Electric Company
Projected Tax Effect of Interest Synchronization Adjustment
12 Months Ended 12/31/2022 and 12/31/2025
(\$000)

Case No.: U-21534
 Exhibit: A-13
 Schedule: C15
 Witness: K. M. Vangilder
 Page: 1 of 1

Line No.	(a) Description	(b) Historical 12/31/2022	(c) Projected 12/31/2025	(d) Source
1	Rate Base	\$ 20,116,777	\$ 22,107,989	Exh. A-12, Sch.B1
2	JDITC Portion of Capital Structure	0.08%	0.07%	Exh. A-14, Sch. D1
3	Debt Portion of Rate Base Funded by JDITC	\$ 16,763	\$ 15,742	Line 1 x Line 2
4	Cost of Long-Term Debt	3.77%	4.24%	Exh. A-14, Sch. D1
5	Imputed Interest	\$ 632	\$ 667	Line 3 x Line 4
6	Composite State and Municipal Income Tax Rate	6.21%	6.21%	Exh. A-13, Sch. C2
7	Effect on State and Municipal Income Tax Expense	\$ (39)	\$ (41)	(Line 5 x Line 6) x -1
8	Effect on Federal Taxable Income	\$ (593)	\$ (626)	(Line 5 + Line 7) x -1
9	Federal Income Tax Rate	21.00%	21.00%	Exh. A-13, Sch. C2
10	Effect on Federal Income Taxes	\$ (125)	\$ (131)	Line 8 x Line 9
11	Synchronization Tax Adjustment to NOI	\$ 164	\$ 172	(Line 7 + Line 10) x -1

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For the 13-Month Average Period Ending Dec. 31, 2025

Case No.: U-21534
Exhibit: A-14
Schedule: D1
Witness: K. M. Vangilder
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	Capital Structure			Cost Rate %	Weighted Costs			
		Amount (\$000)	Percent Permanent Capital (1)	Percent of Total Capital		Permanent Capital	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long-Term Debt	8,663,922 (2)	50.0%	39.19%	4.24% (3)	2.12%	1.66%	1.0000	1.66%
2	Preferred Stock	0	0.0%	0.00%	0.00% (4)	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	8,673,528 (2)	50.0%	39.23%	10.50% (5)	5.25%	4.12%	1.3496	5.56%
4	Total	17,337,450	100.0%			7.37%			
5	Short-Term Debt	509,454 (2)		2.30%	5.76% (6)		0.13%	1.0000	0.13%
6	Investment Tax Credit (ITC) - Debt	15,742		0.07%	4.24%		0.00%	1.0000	0.00%
7	Investment Tax Credit (ITC) - Equity	15,742		0.07%	10.50%		0.01%	1.3496	0.01%
8	Total Investment Tax Credit (ITC)	31,485 (2)							
9	Deferred Income Taxes (Net)	4,229,600 (2)		19.13%	0.000%		0.00%		0.00%
10	Total	22,107,989		100.00%			5.92%		7.37%
11	Rate Base per Exh. A-12, Sch. B1	22,107,989							

- (1) Excludes Short-Term Debt, Deferred Investment Tax Credit, and Deferred Income Taxes to calculate the rate of return for Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation section 1.46-6
(2) See Exh. A-12, Sch. B4.1, Cols. (e) thru (i), Line 121
(3) See Exh. A-14, Sch. D2
(4) See Exh. A-14, Sch. D4
(5) See Exh. A-14, Sch. D5.19
(6) See Exh. A-14, Sch. D3

Authorized ROR Perm Capital (Pretax) for Tree Trim Reg Asset		
Debt	2.12%	Line 1, col. (f) x col. (h)
Equity	7.09%	Line 3, col. (f) x col. (h)
	9.20%	carried to Exhibit A-11 A1.1

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return - Base Rate Request and Monroe Regulatory Asset
For the 13-Month Average Period Ending Dec. 31, 2025

Case No.: U-21534
Exhibit: A-14
Schedule: D1
Witness: K. M. Vangilder
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)
				col. (b) x (c)		col. (d) x (e)
Projected Rate of Return - Base Rate Request (from page 1)						
Line No.	Description	Percent of Total Capital	Cost Rate %	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long-Term Debt	39.19%	4.24%	1.66%	1.0000	1.66%
2	Common Shareholders' Equity	39.23%	10.50%	4.12%	1.3496	5.56%
3	Short-Term Debt	2.30%	5.76%	0.13%	1.0000	0.13%
4	Investment Tax Credit (ITC) - Debt	0.07%	4.24%	0.00%	1.0000	0.00%
5	Investment Tax Credit (ITC) - Equity	0.07%	10.50%	0.01%	1.3496	0.01%
6	Deferred Income Taxes (Net)	19.13%	0.000%	0.00%		0.00%
7	Total	100.00%		5.92%		7.37%
Projected Rate of Return - Monroe Regulatory Asset at 9% ROE						
		Percent of Total Capital	Cost Rate %	Total Cost %	Conversion Factor	Pre-Tax Return
8	Long-Term Debt	39.19%	4.24%	1.66%	1.0000	1.66%
9	Common Shareholders' Equity	39.23%	9.00%	3.53%	1.3496	4.77%
10	Short-Term Debt	2.30%	5.76%	0.13%	1.0000	0.13%
11	Investment Tax Credit (ITC) - Debt	0.07%	4.24%	0.00%	1.0000	0.00%
12	Investment Tax Credit (ITC) - Equity	0.07%	9.00%	0.01%	1.3496	0.01%
13	Deferred Income Taxes (Net)	19.13%	0.00%	0.00%		0.00%
14	Total	100.00%		5.33%		6.57%

Michigan Public Service Commission
DTE Electric Company
Peer Group Common Equity
(\$ millions)

Source: S&P Global Market Intelligence (SNL)
Debt Unadjusted

Case No.: U-21534
Exhibit: A-14
Schedule: D1.1
Witness: T.J. Lepczyk
Page: 1 of 1

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Fiscal Year 2022 (Unless Noted)				Amounts in \$MM				Percentage of Total		
Line	Company Name	Regulated Subsidiary	Year	Long Term Debt	Preferred Stock	Common Stock	Total	Long Term Debt	Preferred Stock	Common Stock
1	ALLETE, Inc.	ALLETE, Inc.	2022	1,921	0	2,692	4,613	41.6%	0.0%	58.4%
2	Alliant Energy Corporation	Interstate Power and Light Company	2022	3,646	0	3,808	7,454	48.9%	0.0%	51.1%
3	Alliant Energy Corporation	Wisconsin Power and Light Company	2022	2,770	0	3,491	6,261	44.2%	0.0%	55.8%
4	Amer Elec Power	AEP Texas	2022	5,658	0	3,904	9,562	59.2%	0.0%	40.8%
5	Amer Elec Power	Appalachian Power Company	2022	5,411	0	4,975	10,386	52.1%	0.0%	47.9%
6	Amer Elec Power	Indiana Michigan Power Co	2022	3,261	0	3,008	6,269	52.0%	0.0%	48.0%
7	Amer Elec Power	Kentucky Power Company	2022	1,178	0	920	2,099	56.1%	0.0%	43.9%
8	Amer Elec Power	Ohio Power Company	2022	2,970	0	3,088	6,058	49.0%	0.0%	51.0%
9	Amer Elec Power	Public Service Company of Oklahoma	2022	1,913	0	2,419	4,332	44.2%	0.0%	55.8%
10	Amer Elec Power	Southwestern Electric Power Company	2022	3,392	0	3,674	7,066	48.0%	0.0%	52.0%
11	Ameren Corporation	Union Electric Company	2022	6,086	80	6,347	12,513	48.6%	0.6%	50.7%
12	Ameren Corporation	Ameren Illinois Company	2022	4,835	49	6,119	11,003	43.9%	0.4%	55.6%
13	Avista Corporation	Alaska Electric Light and Power Company	2022	75	0	117	192	39.1%	0.0%	60.9%
14	Black Hills Corporation	Black Hills Power, Inc.	2022	338	0	551	888	38.0%	0.0%	62.0%
15	CMS Energy Corporation	Consumers Energy Company	2022	10,183	0	10,118	20,301	50.2%	0.0%	49.8%
16	CenterPoint Energy	CenterPoint Energy Houston Electric, LLC	2022	6,353	0	4,998	11,351	56.0%	0.0%	44.0%
17	Duke Energy Corporation	Duke Energy Carolinas, LLC	2022	13,982	0	15,442	29,424	47.5%	0.0%	52.5%
18	Duke Energy Corporation	Duke Energy Florida, LLC	2022	9,668	0	9,023	18,691	51.7%	0.0%	48.3%
19	Duke Energy Corporation	Duke Energy Ohio	2022	3,247	0	4,766	8,013	40.5%	0.0%	59.5%
20	Duke Energy Corporation	Duke Energy Kentucky	2022	779	0	880	1,659	47.0%	0.0%	53.0%
21	Edison International	Southern California Edison Company	2022	26,258	1,945	18,844	47,047	55.8%	4.1%	40.1%
22	Entergy Corporation	Entergy Texas, Inc.	2022	2,896	39	2,641	5,575	51.9%	0.7%	47.4%
23	Entergy Corporation	Entergy Arkansas	2022	4,167	0	3,754	7,920	52.6%	0.0%	47.4%
24	Entergy Corporation	Entergy Mississippi	2022	2,331	0	2,037	4,368	53.4%	0.0%	46.6%
25	Entergy Corporation	Entergy New Orleans	2022	776	0	703	1,478	52.5%	0.0%	47.5%
26	Eversource Energy	Eversource Energy Central, Inc.	2022	3,937	0	4,498	8,435	46.7%	0.0%	53.3%
27	Eversource Energy	Eversource Energy Metro Inc	2022	2,927	0	3,186	6,113	47.9%	0.0%	52.1%
28	Exelon Corporation	Commonwealth Edison Company	2022	10,723	0	13,364	24,087	44.5%	0.0%	55.5%
29	Exelon Corporation	Potomac Electric Power Company	2022	3,726	0	3,782	7,508	49.6%	0.0%	50.4%
30	Exelon Corporation	Delmarva Power & Light Company	2022	1,906	0	1,950	3,856	49.4%	0.0%	50.6%
31	Exelon Corporation	Baltimore Gas and Electric Company	2022	4,207	0	4,936	9,143	46.0%	0.0%	54.0%
32	Exelon Corporation	Atlantic City Electric Company	2022	1,738	0	1,753	3,491	49.8%	0.0%	50.2%
33	Exelon Corporation	PECO Energy Company	2022	4,796	0	5,563	10,359	46.3%	0.0%	53.7%
34	IDACORP, Inc.	Idaho Power Company	2022	2,194	0	2,632	4,826	45.5%	0.0%	54.5%
35	MGE Energy, Inc.	Madison Gas and Electric Company	2022	640	0	854	1,494	42.8%	0.0%	57.2%
36	NextEra Energy	Florida Power and Light Company	2022	21,002	0	38,920	59,922	35.0%	0.0%	65.0%
37	NorthWestern Corporation	NorthWestern Corporation	2022	2,619	0	2,665	5,284	49.6%	0.0%	50.4%
38	OGE Energy Corp.	Oklahoma Gas and Electric Company	2022	3,999	0	5,045	9,044	44.2%	0.0%	55.8%
39	Otter Tail Corporation	Otter Tail Power Company	2022	747	0	909	1,656	45.1%	0.0%	54.9%
40	Pinnacle West Capital	Arizona Public Service Company	2022	6,794	0	6,942	13,735	49.5%	0.0%	50.5%
41	Portland General Electric Co.	Portland General Electric Company	2022	3,671	0	2,779	6,450	56.9%	0.0%	43.1%
42	PPL Corporation	Louisville Gas and Electric Company	2022	2,344	0	3,166	5,510	42.5%	0.0%	57.5%
43	PPL Corporation	Kentucky Utilities Company	2022	2,950	0	4,038	6,988	42.2%	0.0%	57.8%
44	PPL Corporation	PPL Electric Utilities Corporation	2022	4,486	0	5,751	10,237	43.8%	0.0%	56.2%
45	Public Service Enterprise	Public Service Enterprise Group	2022	18,070	0	13,729	31,799	56.8%	0.0%	43.2%
46	Sempra Energy	San Diego Gas & Electric Co.	2022	7,730	0	9,067	16,797	46.0%	0.0%	54.0%
47	Southern Company	Alabama Power Company	2022	10,625	0	11,687	22,312	47.6%	0.0%	52.4%
48	Southern Company	Georgia Power Company	2022	14,672	0	18,858	33,530	43.8%	0.0%	56.2%
49	Southern Company	Mississippi Power Company	2022	1,528	0	1,931	3,459	44.2%	0.0%	55.8%
50	WEC Energy Group, Inc.	Wisconsin Electric Power Company	2022	3,360	30	4,137	7,528	44.6%	0.4%	55.0%
51	WEC Energy Group, Inc.	Wisconsin Public Service Corp	2022	1,958	0	2,383	4,341	45.1%	0.0%	54.9%
52	Xcel Energy Inc.	Northern States Power Company - MN	2022	6,942	0	7,836	14,778	47.0%	0.0%	53.0%
53	Xcel Energy Inc.	Northern States Power Company - WI	2022	1,086	0	1,259	2,345	46.3%	0.0%	53.7%
54	Xcel Energy Inc.	Public Service Company of Colorado	2022	6,860	0	9,230	16,090	42.6%	0.0%	57.4%
55	Xcel Energy Inc.	Southwestern Public Service Company	2022	3,211	0	3,850	7,061	45.5%	0.0%	54.5%
56							Average	47.5%	0.1%	52.4%
57	DTE Energy Company	DTE Electric Company	2022	9,695	0	9,695	19,390	50.0%	0.0%	50.0%

Michigan Public Service Commission
DTE Electric Company
Projected Cost of Long-Term Debt
Projected 12 Month Period Ending December 31, 2025

Case No.: U-21534
Exhibit: A-14
Schedule: D2
Witness: T. J. Lepczyk
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Issue Name	Original Issue Date	Stated Maturity	Interest Rate %	Amount of Offering (\$000)	Price to Public %	Expenses of Financing %	Net Proceeds to the Company %	Cost Based on Net Proceeds %	12/31/2025 Amount Outstanding (\$000)	Annual Cost (\$000)
1	2002 Series B	10/23/02	10/15/32	6.350%	225,000	99.33%	1.0%	98.369%	6.47%	225,000	14,566
2	2005 Series BR	02/07/05	02/15/35	5.450%	200,000	99.59%	1.0%	98.562%	5.55%	200,000	11,098
3	2005 Series E	10/06/05	10/01/37	5.700%	250,000	99.40%	1.0%	98.420%	5.81%	250,000	14,523
4	2006 Series A	06/01/06	06/01/36	6.625%	250,000	99.95%	1.0%	98.954%	6.71%	250,000	16,766
5	2007 Series A	12/18/07	03/15/38	6.470%	50,000	100.00%	0.8%	99.168%	6.53%	50,000	3,266
6	2011 Series E	09/01/11	09/01/26	4.460%	77,000	100.00%	0.6%	99.411%	4.51%	77,000	3,476
7	2011 Series F	09/01/11	09/01/41	5.670%	46,000	100.00%	0.6%	99.411%	5.71%	46,000	2,627
8	2011 Series H	09/20/11	09/01/41	4.500%	140,000	98.87%	1.1%	97.814%	4.64%	140,000	6,490
9	2012 Series B	06/22/12	06/15/42	3.950%	250,000	99.57%	1.0%	98.541%	4.03%	250,000	10,086
10	2013 Series A	03/27/13	04/01/43	4.000%	375,000	99.55%	1.0%	98.500%	4.09%	375,000	15,327
11	2014 Series A	06/04/14	06/01/26	3.770%	100,000	100.00%	0.6%	99.392%	3.83%	100,000	3,834
12	2014 Series B	06/04/14	06/01/44	4.600%	150,000	100.00%	0.6%	99.392%	4.64%	150,000	6,957
13	2014 Series E	07/02/14	07/01/44	4.300%	350,000	99.85%	1.0%	98.832%	4.37%	350,000	15,296
14	2015 Series A	03/11/15	03/15/45	3.700%	500,000	99.77%	1.0%	98.735%	3.77%	500,000	18,854
15	2016 Series A	05/17/16	06/01/46	3.700%	300,000	99.93%	1.1%	98.824%	3.77%	300,000	11,297
16	2017 Series B	08/09/17	08/15/47	3.750%	440,000	99.95%	1.1%	98.850%	3.81%	440,000	16,784
17	2018 Series A	05/07/18	05/15/48	4.050%	525,000	99.55%	1.1%	98.456%	4.14%	525,000	21,736
18	2019 Series A	02/15/19	03/01/49	3.950%	650,000	99.20%	1.1%	98.111%	4.06%	650,000	26,385
19	2020 Series A	02/26/20	03/01/30	2.250%	600,000	99.88%	0.8%	99.042%	2.36%	600,000	14,148
20	2020 Series B	02/26/20	03/01/50	2.950%	500,000	99.96%	1.1%	98.893%	3.01%	500,000	15,031
21	2020 Series C	04/06/20	03/01/31	2.625%	600,000	99.83%	0.8%	99.004%	2.73%	600,000	16,387
22	2021 Green Series A 11C	03/29/21	04/01/28	1.900%	575,000	99.92%	0.9%	99.062%	2.04%	575,000	11,756
23	2021 Green Series B 11C	03/29/21	04/01/51	3.250%	425,000	99.17%	1.1%	98.062%	3.35%	425,000	14,250
24	1995CC 2021 Remarket	09/01/21	09/01/30	1.450%	82,350	100.00%	0.7%	99.317%	1.53%	82,350	1,261
25	2008ET2 2021 Remarket	09/01/21	08/01/29	1.350%	59,175	100.00%	0.7%	99.310%	1.44%	59,175	854
26	2022 Series A 110091	02/24/22	03/01/32	3.000%	500,000	99.60%	0.9%	98.696%	3.15%	500,000	15,764
27	2022 Green Series B 11C	02/24/22	03/01/52	3.650%	400,000	99.39%	1.1%	98.260%	3.75%	400,000	14,988
28	2023 Series A 110093	03/03/23	04/01/33	5.200%	600,000	99.79%	0.9%	98.908%	5.34%	600,000	32,045
29	2023 Series B 110094	03/03/23	04/01/53	5.400%	600,000	99.82%	1.1%	98.707%	5.49%	600,000	32,928
30	2023DT Series 110095	06/01/23	06/03/30	3.875%	100,000	100.00%	1.3%	98.730%	4.09%	100,000	4,085
31	2024 Series A	03/01/24	03/01/54	5.650%	575,000	100.00%	1.0%	99.00%	5.72%	575,000	32,891
32	2025 Series A	03/01/25	03/01/55	5.620%	800,000	100.00%	1.0%	99.00%	5.69%	800,000	45,519
33	2025 Series B	07/01/25	07/01/55	5.620%	500,000	100.00%	1.0%	99.00%	5.69%	500,000	28,449
									4.24%	11,794,525	499,723

Michigan Public Service Commission
DTE Electric Company
Projected Cost of Short-Term Debt
For Period Ending December 31, 2025

Case No.: U-21534
 Exhibit: A-14
 Schedule: D3
 Witness: T. J. Lepczyk
 Page: 1 of 1

Line No.	(a) Description	(b) 12 Months Ending 12/31/2025	(c) Reference
	Short Term Debt Cost Rate:		
1	Forward Short-Term debt rate	5.31%	Short-Term Index Forecast
2	Spread to Short-Term debt rate	<u>0.20%</u>	Spread per history
3	Interest rate on short-term borrowings	5.51%	Interest rate on short-term borrowings
4	Credit facility fees (\$000)	1,297	Costs for 12 month period ending December 31, 2025
5	Average short-term debt balance (\$000)	509,454	Exhibit A-12, B4.1
6	Credit agreement cost for test period (%)	0.25%	Line 4 ÷ Line 5
7	Total Cost of Short Term Debt	5.76%	Line 3 + Line 6

**Michigan Public Service Commission
DTE Electric Company
Projected Cost of Preferred and Preference Stock
For Period Ending December 31, 2025**

Case No.: U-21534
Exhibit: A-14
Schedule: D4
Witness: T. J. Lepczyk
Page: 1 of 1

The Company has no plans to have Preferred or Preference Stock
outstanding during 2023 thru 2025

**Michigan Public Service Commission
DTE Electric Company
Projected Cost of Common Shareholders' Equity
Twelve Months ended December 31, 2025**

Case No.: U-21534
Exhibit: A-14
Schedule: D5
Witness: B. Villadsen
Page: 1 of 1

Projected Cost of Common Shareholders' Equity

10.50%

Schedule No. D5.1

Table of Contents

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Schedule No. D5.19	Available Regulatory Mechanisms

Schedule No. D5.2

Electric Sample

Classification of Companies by Assets

Company	Company Category
ALLETE	MR
Alliant Energy	R
Amer. Elec. Power	R
Ameren Corp.	R
Avista Corp.	R
Black Hills	R
CMS Energy Corp.	R
CenterPoint Energy	R
Duke Energy	R
Edison Int'l	R
Entergy Corp.	R
Eversource Inc.	R
Exelon Corp.	R
IDACORP Inc.	R
MGE Energy	R
NextEra Energy	MR
NorthWestern Corp.	R
OGE Energy	R
Otter Tail Corp.	R
Pinnacle West Capital	R
Public Serv. Enterprise	R
Sempra Energy	R
Southern Co.	R
WEC Energy Group	R
Xcel Energy Inc.	R

Sources and Notes:

Based on EEI 2022 Financial Review:

R = Regulated (greater than 80 percent of total assets are regulated).

MR = Mostly Regulated (Less than 80 percent of total assets are regulated).

Schedule No. D5.3

Market Value of the Electric Sample

Panel A: ALLETE

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$2,787	\$2,787	\$2,692	\$2,413	\$2,295	\$2,232	\$2,156
Shares Outstanding (in millions) - Common	58	58	57	53	52	52	51
Price per Share - Common	\$61	\$61	\$65	\$65	\$60	\$81	\$78
Market Value of Common Equity	\$3,509	\$3,509	\$3,702	\$3,433	\$3,139	\$4,146	\$3,969
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$3,509	\$3,509	\$3,702	\$3,433	\$3,139	\$4,146	\$3,969
Market to Book Value of Common Equity	1.26	1.26	1.38	1.42	1.37	1.86	1.84
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$503	\$503	\$718	\$291	\$255	\$270	\$334
Current Liabilities	\$414	\$414	\$716	\$543	\$460	\$507	\$405
Current Portion of Long-Term Debt	\$114	\$114	\$276	\$219	\$210	\$220	\$58
Net Working Capital	\$204	\$204	\$278	(\$33)	\$5	(\$18)	(\$13)
Notes Payable (Short-Term Debt)	na	na	na	na	na	na	na
Adjusted Short-Term Debt	\$0	\$0	\$0	na	\$0	na	na
Long-Term Debt	\$1,695	\$1,695	\$1,658	\$1,775	\$1,610	\$1,423	\$1,429
Book Value of Long-Term Debt	\$1,809	\$1,809	\$1,933	N/A	\$1,819	N/A	N/A
Unadjusted Market Value of Long Term Debt	\$1,783	\$1,783	\$2,193	\$2,122	\$1,792	\$1,535	\$1,628
Carrying Amount	\$1,929	\$1,929	\$1,986	\$1,806	\$1,623	\$1,495	\$1,513
Adjustment to Book Value of Long-Term Debt	(\$146)	(\$146)	\$206	\$316	\$169	\$39	\$114
Market Value of Long-Term Debt	\$1,662	\$1,662	\$2,140	N/A	\$1,989	N/A	N/A
Market Value of Debt	\$1,662	\$1,662	\$2,140	N/A	\$1,989	N/A	N/A
MARKET VALUE OF FIRM							
	\$5,171	\$5,171	\$5,842	N/A	\$5,128	N/A	N/A
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	67.86%	67.86%	63.37%	N/A	61.22%	N/A	N/A
Preferred Equity - Market Value Ratio	-	-	-	N/A	-	N/A	N/A
Debt - Market Value Ratio	32.14%	32.14%	36.63%	N/A	38.78%	N/A	N/A

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

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(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel B: Alliant Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$6,726	\$6,726	\$6,276	\$5,990	\$5,688	\$5,205	\$4,586
Shares Outstanding (in millions) - Common	255	255	251	250	250	245	236
Price per Share - Common	\$51	\$51	\$55	\$60	\$51	\$54	\$44
Market Value of Common Equity	\$13,077	\$13,077	\$13,903	\$15,070	\$12,741	\$13,207	\$10,352
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$13,077	\$13,077	\$13,903	\$15,070	\$12,741	\$13,207	\$10,352
Market to Book Value of Common Equity	1.94	1.94	2.22	2.52	2.24	2.54	2.26
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$200	\$200	\$200
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$200	\$200	\$200
MARKET VALUE OF DEBT							
Current Assets	\$1,372	\$1,372	\$1,250	\$1,069	\$887	\$876	\$785
Current Liabilities	\$1,935	\$1,935	\$2,363	\$2,054	\$1,297	\$2,054	\$1,644
Current Portion of Long-Term Debt	\$409	\$409	\$411	\$635	\$10	\$659	\$257
Net Working Capital	(\$154)	(\$154)	(\$702)	(\$350)	(\$400)	(\$519)	(\$603)
Notes Payable (Short-Term Debt)	\$501	\$501	\$642	\$515	\$389	\$337	\$441
Adjusted Short-Term Debt	\$154	\$154	\$642	\$350	\$389	\$337	\$441
Long-Term Debt	\$8,429	\$8,429	\$7,681	\$6,747	\$6,782	\$5,547	\$5,246
Book Value of Long-Term Debt	\$8,992	\$8,992	\$8,734	\$7,732	\$7,181	\$6,543	\$5,944
Unadjusted Market Value of Long Term Debt	\$7,339	\$7,339	\$8,330	\$8,109	\$6,920	\$5,861	\$5,448
Carrying Amount	\$8,076	\$8,076	\$7,368	\$6,777	\$6,190	\$5,503	\$4,866
Adjustment to Book Value of Long-Term Debt	(\$737)	(\$737)	\$962	\$1,332	\$730	\$358	\$581
Market Value of Long-Term Debt	\$8,255	\$8,255	\$9,696	\$9,064	\$7,911	\$6,901	\$6,525
Market Value of Debt	\$8,255	\$8,255	\$9,696	\$9,064	\$7,911	\$6,901	\$6,525
MARKET VALUE OF FIRM							
	\$21,332	\$21,332	\$23,599	\$24,134	\$20,852	\$20,308	\$17,077
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	61.30%	61.30%	58.91%	62.44%	61.10%	65.03%	60.62%
Preferred Equity - Market Value Ratio	-	-	-	-	0.96%	0.98%	1.17%
Debt - Market Value Ratio	38.70%	38.70%	41.09%	37.56%	37.94%	33.98%	38.21%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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Prices are reported in Workpaper #1 to Schedule No. D5.6.

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(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel C: Amer. Elec. Power

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$25,385	\$25,385	\$23,939	\$22,477	\$20,596	\$19,675	\$19,068
Shares Outstanding (in millions) - Common	526	526	514	504	497	494	493
Price per Share - Common	\$81	\$81	\$96	\$87	\$82	\$93	\$77
Market Value of Common Equity	\$42,680	\$42,680	\$49,268	\$43,850	\$40,874	\$46,134	\$38,043
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$42,680	\$42,680	\$49,268	\$43,850	\$40,874	\$46,134	\$38,043
Market to Book Value of Common Equity	1.68	1.68	2.06	1.95	1.98	2.34	2.00
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$6,737	\$6,737	\$9,419	\$7,809	\$4,352	\$4,078	\$4,114
Current Liabilities	\$11,278	\$11,278	\$14,567	\$12,427	\$9,927	\$10,299	\$8,649
Current Portion of Long-Term Debt	\$2,891	\$2,891	\$2,110	\$2,251	\$2,327	\$1,833	\$1,699
Net Working Capital	(\$1,650)	(\$1,650)	(\$3,039)	(\$2,366)	(\$3,248)	(\$4,389)	(\$2,836)
Notes Payable (Short-Term Debt)	\$2,730	\$2,730	\$4,112	\$2,614	\$2,479	\$2,838	\$1,910
Adjusted Short-Term Debt	\$1,650	\$1,650	\$3,039	\$2,366	\$2,479	\$2,838	\$1,910
Long-Term Debt	\$37,230	\$37,230	\$34,178	\$31,794	\$29,625	\$25,861	\$21,648
Book Value of Long-Term Debt	\$41,772	\$41,772	\$39,327	\$36,411	\$34,432	\$30,533	\$25,257
Unadjusted Market Value of Long Term Debt	\$31,767	\$31,767	\$37,565	\$37,457	\$30,172	\$24,094	\$23,650
Carrying Amount	\$35,623	\$35,623	\$33,455	\$31,073	\$26,726	\$23,347	\$21,173
Adjustment to Book Value of Long-Term Debt	(\$3,856)	(\$3,856)	\$4,110	\$6,385	\$3,447	\$747	\$2,476
Market Value of Long-Term Debt	\$37,916	\$37,916	\$43,437	\$42,796	\$37,878	\$31,280	\$27,733
Market Value of Debt	\$37,916	\$37,916	\$43,437	\$42,796	\$37,878	\$31,280	\$27,733
MARKET VALUE OF FIRM							
	\$80,596	\$80,596	\$92,705	\$86,646	\$78,752	\$77,414	\$65,776
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	52.96%	52.96%	53.14%	50.61%	51.90%	59.59%	57.84%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	47.04%	47.04%	46.86%	49.39%	48.10%	40.41%	42.16%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel D: Ameren Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$11,043	\$11,043	\$10,508	\$9,700	\$8,938	\$8,059	\$7,631
Shares Outstanding (in millions) - Common	263	263	258	258	253	246	245
Price per Share - Common	\$74	\$74	\$89	\$88	\$77	\$76	\$67
Market Value of Common Equity	\$19,455	\$19,455	\$22,943	\$22,617	\$19,598	\$18,635	\$16,463
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$19,455	\$19,455	\$22,943	\$22,617	\$19,598	\$18,635	\$16,463
Market to Book Value of Common Equity	1.76	1.76	2.18	2.33	2.19	2.31	2.16
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$2,084	\$2,084	\$2,668	\$1,968	\$1,653	\$1,431	\$1,533
Current Liabilities	\$4,017	\$4,017	\$3,366	\$2,826	\$2,180	\$2,505	\$2,687
Current Portion of Long-Term Debt	\$849	\$849	\$340	\$505	\$8	\$449	\$580
Net Working Capital	(\$1,084)	(\$1,084)	(\$358)	(\$353)	(\$519)	(\$625)	(\$574)
Notes Payable (Short-Term Debt)	\$1,340	\$1,340	\$1,070	\$545	\$490	\$440	\$597
Adjusted Short-Term Debt	\$1,084	\$1,084	\$358	\$353	\$490	\$440	\$574
Long-Term Debt	\$13,829	\$13,829	\$13,685	\$12,562	\$11,078	\$8,944	\$7,859
Book Value of Long-Term Debt	\$15,762	\$15,762	\$14,383	\$13,420	\$11,576	\$9,833	\$9,013
Unadjusted Market Value of Long Term Debt	\$12,453	\$12,453	\$14,521	\$13,315	\$10,441	\$8,669	\$8,531
Carrying Amount	\$14,025	\$14,025	\$13,067	\$11,086	\$9,357	\$8,439	\$7,935
Adjustment to Book Value of Long-Term Debt	(\$1,572)	(\$1,572)	\$1,454	\$2,229	\$1,084	\$230	\$596
Market Value of Long-Term Debt	\$14,190	\$14,190	\$15,837	\$15,649	\$12,660	\$10,063	\$9,609
Market Value of Debt	\$14,190	\$14,190	\$15,837	\$15,649	\$12,660	\$10,063	\$9,609
MARKET VALUE OF FIRM	\$33,645	\$33,645	\$38,780	\$38,266	\$32,258	\$28,698	\$26,072
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	57.82%	57.82%	59.16%	59.11%	60.75%	64.94%	63.14%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	42.18%	42.18%	40.84%	40.89%	39.25%	35.06%	36.86%

Sources and Notes:

Bloomberg as of December 31, 2023

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(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel E: Avista Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$2,410	\$2,410	\$2,335	\$2,155	\$2,030	\$1,939	\$1,773
Shares Outstanding (in millions) - Common	77	77	75	71	69	67	66
Price per Share - Common	\$35	\$35	\$43	\$41	\$39	\$48	\$44
Market Value of Common Equity	\$2,744	\$2,744	\$3,238	\$2,961	\$2,732	\$3,231	\$2,868
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$2,744	\$2,744	\$3,238	\$2,961	\$2,732	\$3,231	\$2,868
Market to Book Value of Common Equity	1.14	1.14	1.39	1.37	1.35	1.67	1.62
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$547	\$547	\$722	\$434	\$344	\$305	\$347
Current Liabilities	\$583	\$583	\$965	\$913	\$506	\$531	\$640
Current Portion of Long-Term Debt	\$3	\$3	\$21	\$257	\$7	\$59	\$108
Net Working Capital	(\$33)	(\$33)	(\$222)	(\$221)	(\$155)	(\$167)	(\$185)
Notes Payable (Short-Term Debt)	\$222	\$222	\$463	\$284	\$203	\$186	\$190
Adjusted Short-Term Debt	\$33	\$33	\$222	\$221	\$155	\$167	\$185
Long-Term Debt	\$2,689	\$2,689	\$2,439	\$2,062	\$2,177	\$2,013	\$1,807
Book Value of Long-Term Debt	\$2,725	\$2,725	\$2,682	\$2,540	\$2,339	\$2,238	\$2,100
Unadjusted Market Value of Long Term Debt	\$967	\$967	\$1,158	\$1,190	\$1,125	\$1,142	\$1,068
Carrying Amount	\$1,114	\$1,114	\$964	\$964	\$964	\$1,054	\$951
Adjustment to Book Value of Long-Term Debt	(\$147)	(\$147)	\$194	\$226	\$161	\$89	\$117
Market Value of Long-Term Debt	\$2,578	\$2,578	\$2,876	\$2,767	\$2,500	\$2,327	\$2,217
Market Value of Debt	\$2,578	\$2,578	\$2,876	\$2,767	\$2,500	\$2,327	\$2,217
MARKET VALUE OF FIRM	\$5,322	\$5,322	\$6,114	\$5,728	\$5,232	\$5,558	\$5,085
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	51.56%	51.56%	52.96%	51.70%	52.22%	58.13%	56.41%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	48.44%	48.44%	47.04%	48.30%	47.78%	41.87%	43.59%

Sources and Notes:

Bloomberg as of December 31, 2023

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(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel F: Black Hills

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$3,167	\$3,167	\$2,995	\$2,787	\$2,561	\$2,362	\$2,182
Shares Outstanding (in millions) - Common	68	68	66	65	63	61	60
Price per Share - Common	\$54	\$54	\$70	\$69	\$60	\$78	\$64
Market Value of Common Equity	\$3,700	\$3,700	\$4,618	\$4,469	\$3,767	\$4,782	\$3,865
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$3,700	\$3,700	\$4,618	\$4,469	\$3,767	\$4,782	\$3,865
Market to Book Value of Common Equity	1.17	1.17	1.54	1.60	1.47	2.02	1.77
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$1,240	\$1,240	\$1,072	\$808	\$493	\$473	\$504
Current Liabilities	\$1,603	\$1,603	\$1,667	\$902	\$697	\$811	\$648
Current Portion of Long-Term Debt	\$1,125	\$1,125	\$525	\$0	\$9	\$7	\$6
Net Working Capital	\$763	\$763	(\$70)	(\$94)	(\$194)	(\$331)	(\$139)
Notes Payable (Short-Term Debt)	\$0	\$0	\$536	\$420	\$234	\$350	\$186
Adjusted Short-Term Debt	\$0	\$0	\$70	\$94	\$194	\$331	\$139
Long-Term Debt	\$3,800	\$3,800	\$3,607	\$4,127	\$3,532	\$3,144	\$2,951
Book Value of Long-Term Debt	\$4,925	\$4,925	\$4,202	\$4,221	\$3,735	\$3,482	\$3,095
Unadjusted Market Value of Long Term Debt	\$3,761	\$3,761	\$4,571	\$4,208	\$3,479	\$3,039	\$3,351
Carrying Amount	\$4,132	\$4,132	\$4,127	\$3,537	\$3,146	\$2,957	\$3,115
Adjustment to Book Value of Long-Term Debt	(\$371)	(\$371)	\$444	\$672	\$334	\$83	\$235
Market Value of Long-Term Debt	\$4,553	\$4,553	\$4,646	\$4,892	\$4,069	\$3,565	\$3,331
Market Value of Debt	\$4,553	\$4,553	\$4,646	\$4,892	\$4,069	\$3,565	\$3,331
MARKET VALUE OF FIRM							
	\$8,253	\$8,253	\$9,264	\$9,361	\$7,836	\$8,346	\$7,195
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	44.83%	44.83%	49.85%	47.74%	48.07%	57.29%	53.71%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	55.17%	55.17%	50.15%	52.26%	51.93%	42.71%	46.29%

Sources and Notes:

Bloomberg as of December 31, 2023

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(1): 0 if [m] > 0.

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(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel G: CMS Energy Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$7,320	\$7,320	\$6,791	\$6,407	\$5,496	\$5,018	\$4,755
Shares Outstanding (in millions) - Common	294	294	291	290	289	284	283
Price per Share - Common	\$58	\$58	\$63	\$64	\$59	\$62	\$51
Market Value of Common Equity	\$17,065	\$17,065	\$18,386	\$18,614	\$17,070	\$17,626	\$14,491
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$17,065	\$17,065	\$18,386	\$18,614	\$17,070	\$17,626	\$14,491
Market to Book Value of Common Equity	2.33	2.33	2.71	2.91	3.11	3.51	3.05
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$224	\$224	\$224	\$224	\$0	\$0	\$0
Market Value of Preferred Equity	\$224	\$224	\$224	\$224	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$2,839	\$2,839	\$3,433	\$2,627	\$2,404	\$2,331	\$2,468
Current Liabilities	\$2,895	\$2,895	\$2,985	\$2,204	\$3,074	\$2,704	\$2,624
Current Portion of Long-Term Debt	\$984	\$984	\$1,103	\$385	\$598	\$1,139	\$996
Net Working Capital	\$928	\$928	\$1,551	\$808	(\$72)	\$766	\$840
Notes Payable (Short-Term Debt)	\$93	\$93	\$20	\$0	\$0	\$90	\$97
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Long-Term Debt	\$14,592	\$14,592	\$13,217	\$12,115	\$11,825	\$12,064	\$10,684
Book Value of Long-Term Debt	\$15,576	\$15,576	\$14,320	\$12,500	\$12,423	\$13,203	\$11,680
Unadjusted Market Value of Long Term Debt	\$12,384	\$12,384	\$13,800	\$17,512	\$14,185	\$11,630	\$10,715
Carrying Amount	\$14,212	\$14,212	\$12,419	\$15,120	\$13,062	\$11,589	\$10,204
Adjustment to Book Value of Long-Term Debt	(\$1,828)	(\$1,828)	\$1,381	\$2,392	\$1,123	\$41	\$511
Market Value of Long-Term Debt	\$13,748	\$13,748	\$15,701	\$14,892	\$13,546	\$13,244	\$12,191
Market Value of Debt	\$13,748	\$13,748	\$15,701	\$14,892	\$13,546	\$13,244	\$12,191
MARKET VALUE OF FIRM							
	\$31,037	\$31,037	\$34,311	\$33,730	\$30,616	\$30,870	\$26,682
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	54.98%	54.98%	53.59%	55.19%	55.76%	57.10%	54.31%
Preferred Equity - Market Value Ratio	0.72%	0.72%	0.65%	0.66%	-	-	-
Debt - Market Value Ratio	44.30%	44.30%	45.76%	44.15%	44.24%	42.90%	45.69%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel H: CenterPoint Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$9,585	\$9,585	\$9,255	\$8,628	\$5,985	\$6,619	\$6,318
Shares Outstanding (in millions) - Common	631	631	630	629	551	501	501
Price per Share - Common	\$29	\$29	\$30	\$28	\$22	\$26	\$28
Market Value of Common Equity	\$18,194	\$18,194	\$19,195	\$17,407	\$11,901	\$13,213	\$14,245
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$18,194	\$18,194	\$19,195	\$17,407	\$11,901	\$13,213	\$14,245
Market to Book Value of Common Equity	1.90	1.90	2.07	2.02	1.99	2.00	2.25
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$800	\$800	\$2,402	\$1,740	\$1,740
Market Value of Preferred Equity	\$0	\$0	\$800	\$800	\$2,402	\$1,740	\$1,740
MARKET VALUE OF DEBT							
Current Assets	\$3,022	\$3,022	\$4,699	\$7,355	\$2,920	\$3,937	\$7,025
Current Liabilities	\$3,893	\$3,893	\$5,113	\$4,277	\$4,786	\$3,978	\$3,302
Current Portion of Long-Term Debt	\$1,430	\$1,430	\$1,514	\$534	\$1,886	\$875	\$482
Net Working Capital	\$559	\$559	\$1,100	\$3,612	\$20	\$834	\$4,205
Notes Payable (Short-Term Debt)	\$634	\$634	\$1,089	\$910	\$953	\$893	\$601
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Long-Term Debt	\$16,430	\$16,430	\$14,689	\$15,258	\$11,011	\$13,522	\$8,682
Book Value of Long-Term Debt	\$17,860	\$17,860	\$16,203	\$15,792	\$12,897	\$14,397	\$9,164
Unadjusted Market Value of Long Term Debt	\$14,990	\$14,990	\$17,385	\$15,226	\$16,067	\$9,140	\$8,679
Carrying Amount	\$17,385	\$17,385	\$16,086	\$13,401	\$15,093	\$9,308	\$9,220
Adjustment to Book Value of Long-Term Debt	(\$2,395)	(\$2,395)	\$1,299	\$1,825	\$974	(\$168)	(\$541)
Market Value of Long-Term Debt	\$15,465	\$15,465	\$17,502	\$17,617	\$13,871	\$14,229	\$8,623
Market Value of Debt	\$15,465	\$15,465	\$17,502	\$17,617	\$13,871	\$14,229	\$8,623
MARKET VALUE OF FIRM							
	\$33,659	\$33,659	\$37,497	\$35,824	\$28,174	\$29,182	\$24,608
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	54.05%	54.05%	51.19%	48.59%	42.24%	45.28%	57.89%
Preferred Equity - Market Value Ratio	-	-	2.13%	2.23%	8.53%	5.96%	7.07%
Debt - Market Value Ratio	45.95%	45.95%	46.68%	49.18%	49.23%	48.76%	35.04%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

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(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel I: Duke Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$47,150	\$47,150	\$47,360	\$47,334	\$46,002	\$44,860	\$43,817
Shares Outstanding (in millions) - Common	771	771	770	769	769	769	727
Price per Share - Common	\$97	\$97	\$102	\$104	\$91	\$90	\$88
Market Value of Common Equity	\$74,426	\$74,426	\$78,674	\$79,661	\$69,649	\$69,398	\$63,922
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$74,426	\$74,426	\$78,674	\$79,661	\$69,649	\$69,398	\$63,922
Market to Book Value of Common Equity	1.58	1.58	1.66	1.68	1.51	1.55	1.46
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$1,962	\$1,962	\$1,962	\$1,962	\$1,962	\$1,962	\$0
Market Value of Preferred Equity	\$1,962	\$1,962	\$1,962	\$1,962	\$1,962	\$1,962	\$0
MARKET VALUE OF DEBT							
Current Assets	\$12,769	\$12,769	\$13,222	\$9,940	\$8,682	\$9,163	\$9,714
Current Liabilities	\$17,283	\$17,283	\$18,873	\$15,931	\$16,305	\$14,752	\$15,041
Current Portion of Long-Term Debt	\$2,800	\$2,800	\$4,944	\$4,335	\$4,544	\$3,468	\$3,410
Net Working Capital	(\$1,714)	(\$1,714)	(\$707)	(\$1,656)	(\$3,079)	(\$2,121)	(\$1,917)
Notes Payable (Short-Term Debt)	\$4,288	\$4,288	\$3,952	\$3,304	\$2,873	\$3,135	\$3,406
Adjusted Short-Term Debt	\$1,714	\$1,714	\$707	\$1,656	\$2,873	\$2,121	\$1,917
Long-Term Debt	\$73,369	\$73,369	\$67,937	\$61,388	\$56,965	\$56,417	\$52,064
Book Value of Long-Term Debt	\$77,883	\$77,883	\$73,588	\$67,379	\$64,382	\$62,006	\$57,391
Unadjusted Market Value of Long Term Debt	\$69,292	\$69,292	\$69,292	\$69,292	\$63,062	\$54,534	\$55,331
Carrying Amount	\$59,863	\$59,863	\$59,863	\$59,863	\$58,126	\$54,529	\$52,279
Adjustment to Book Value of Long-Term Debt	\$9,429	\$9,429	\$9,429	\$9,429	\$4,936	\$5	\$3,052
Market Value of Long-Term Debt	\$87,312	\$87,312	\$83,017	\$76,808	\$69,318	\$62,011	\$60,443
Market Value of Debt	\$87,312	\$87,312	\$83,017	\$76,808	\$69,318	\$62,011	\$60,443
MARKET VALUE OF FIRM							
	\$163,700	\$163,700	\$163,653	\$158,431	\$140,929	\$133,371	\$124,365
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	45.46%	45.46%	48.07%	50.28%	49.42%	52.03%	51.40%
Preferred Equity - Market Value Ratio	1.20%	1.20%	1.20%	1.24%	1.39%	1.47%	-
Debt - Market Value Ratio	53.34%	53.34%	50.73%	48.48%	49.19%	46.50%	48.60%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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Prices are reported in Workpaper #1 to Schedule No. D5.6.

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(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel J: Edison Int'l

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$13,692	\$13,692	\$13,643	\$13,911	\$14,048	\$13,303	\$10,459
Shares Outstanding (in millions) - Common	384	384	382	380	379	362	326
Price per Share - Common	\$70	\$70	\$66	\$67	\$62	\$74	\$58
Market Value of Common Equity	\$26,793	\$26,793	\$25,077	\$25,664	\$23,634	\$26,731	\$18,821
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$26,793	\$26,793	\$25,077	\$25,664	\$23,634	\$26,731	\$18,821
Market to Book Value of Common Equity	1.96	1.96	1.84	1.84	1.68	2.01	1.80
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$3,879	\$3,879	\$3,879	\$3,878	\$1,901	\$2,193	\$2,193
Market Value of Preferred Equity	\$3,879	\$3,879	\$3,879	\$3,878	\$1,901	\$2,193	\$2,193
MARKET VALUE OF DEBT							
Current Assets	\$7,235	\$7,235	\$7,070	\$5,491	\$5,061	\$3,560	\$3,359
Current Liabilities	\$9,027	\$9,027	\$10,347	\$8,609	\$10,277	\$5,523	\$5,395
Current Portion of Long-Term Debt	\$3,118	\$3,118	\$3,120	\$1,659	\$1,244	\$559	\$79
Net Working Capital	\$1,326	\$1,326	(\$157)	(\$1,459)	(\$3,972)	(\$1,404)	(\$1,957)
Notes Payable (Short-Term Debt)	\$1,005	\$1,005	\$2,015	\$2,354	\$2,398	\$550	\$720
Adjusted Short-Term Debt	\$0	\$0	\$157	\$1,459	\$2,398	\$550	\$720
Long-Term Debt	\$30,645	\$30,645	\$27,961	\$25,520	\$20,505	\$18,477	\$14,668
Book Value of Long-Term Debt	\$33,763	\$33,763	\$31,238	\$28,638	\$24,147	\$19,586	\$15,467
Unadjusted Market Value of Long Term Debt	\$26,824	\$26,824	\$27,718	\$23,824	\$20,137	\$14,844	\$13,760
Carrying Amount	\$29,639	\$29,639	\$25,247	\$20,337	\$18,343	\$14,711	\$12,123
Adjustment to Book Value of Long-Term Debt	(\$2,815)	(\$2,815)	\$2,471	\$3,487	\$1,794	\$133	\$1,637
Market Value of Long-Term Debt	\$30,948	\$30,948	\$33,709	\$32,125	\$25,941	\$19,719	\$17,104
Market Value of Debt	\$30,948	\$30,948	\$33,709	\$32,125	\$25,941	\$19,719	\$17,104
MARKET VALUE OF FIRM							
	\$61,620	\$61,620	\$62,665	\$61,667	\$51,476	\$48,643	\$38,118
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	43.48%	43.48%	40.02%	41.62%	45.91%	54.95%	49.38%
Preferred Equity - Market Value Ratio	6.30%	6.30%	6.19%	6.29%	3.69%	4.51%	5.75%
Debt - Market Value Ratio	50.22%	50.22%	53.79%	52.09%	50.39%	40.54%	44.87%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel K: Entergy Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$13,691	\$13,691	\$12,967	\$11,637	\$10,926	\$10,224	\$8,844
Shares Outstanding (in millions) - Common	211	211	211	203	200	199	189
Price per Share - Common	\$101	\$101	\$115	\$110	\$99	\$119	\$87
Market Value of Common Equity	\$21,439	\$21,439	\$24,267	\$22,304	\$19,835	\$23,696	\$16,477
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$21,439	\$21,439	\$24,267	\$22,304	\$19,835	\$23,696	\$16,477
Market to Book Value of Common Equity	1.57	1.57	1.87	1.92	1.82	2.32	1.86
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$347	\$347	\$317	\$288	\$254	\$254	\$219
Market Value of Preferred Equity	\$347	\$347	\$317	\$288	\$254	\$254	\$219
MARKET VALUE OF DEBT							
Current Assets	\$5,330	\$5,330	\$4,095	\$3,624	\$4,560	\$3,046	\$2,958
Current Liabilities	\$5,849	\$5,849	\$6,369	\$6,191	\$7,061	\$5,620	\$5,444
Current Portion of Long-Term Debt	\$1,524	\$1,524	\$2,366	\$1,099	\$1,223	\$848	\$652
Net Working Capital	\$1,005	\$1,005	\$91	(\$1,468)	(\$1,278)	(\$1,727)	(\$1,834)
Notes Payable (Short-Term Debt)	\$1,351	\$1,351	\$828	\$1,201	\$1,627	\$1,947	\$1,942
Adjusted Short-Term Debt	\$0	\$0	\$0	\$1,201	\$1,278	\$1,727	\$1,834
Long-Term Debt	\$24,659	\$24,659	\$23,758	\$24,994	\$21,377	\$17,260	\$15,539
Book Value of Long-Term Debt	\$26,183	\$26,183	\$26,124	\$27,294	\$23,877	\$19,834	\$18,024
Unadjusted Market Value of Long Term Debt	\$22,574	\$22,574	\$27,061	\$24,814	\$19,060	\$15,880	\$15,367
Carrying Amount	\$25,933	\$25,933	\$25,881	\$22,370	\$17,874	\$16,168	\$15,075
Adjustment to Book Value of Long-Term Debt	(\$3,359)	(\$3,359)	\$1,180	\$2,444	\$1,186	(\$288)	\$292
Market Value of Long-Term Debt	\$22,825	\$22,825	\$27,304	\$29,738	\$25,064	\$19,546	\$18,316
Market Value of Debt	\$22,825	\$22,825	\$27,304	\$29,738	\$25,064	\$19,546	\$18,316
MARKET VALUE OF FIRM	\$44,610	\$44,610	\$51,889	\$52,330	\$45,154	\$43,497	\$35,012
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	48.06%	48.06%	46.77%	42.62%	43.93%	54.48%	47.06%
Preferred Equity - Market Value Ratio	0.78%	0.78%	0.61%	0.55%	0.56%	0.58%	0.63%
Debt - Market Value Ratio	51.16%	51.16%	52.62%	56.83%	55.51%	44.94%	52.31%

Sources and Notes:

Bloomberg as of December 31, 2023

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(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel L: Evergy Inc.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$9,749	\$9,749	\$9,484	\$9,244	\$8,733	\$8,572	\$10,028
Shares Outstanding (in millions) - Common	230	230	230	229	227	227	255
Price per Share - Common	\$52	\$52	\$63	\$67	\$54	\$64	\$58
Market Value of Common Equity	\$11,915	\$11,915	\$14,421	\$15,478	\$12,240	\$14,420	\$14,898
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$11,915	\$11,915	\$14,421	\$15,478	\$12,240	\$14,420	\$14,898
Market to Book Value of Common Equity	1.22	1.22	1.52	1.67	1.40	1.68	1.49
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$1,896	\$1,896	\$1,842	\$1,710	\$1,624	\$1,468	\$1,681
Current Liabilities	\$4,810	\$4,810	\$3,494	\$3,103	\$2,356	\$2,336	\$2,867
Current Portion of Long-Term Debt	\$889	\$889	\$455	\$406	\$470	\$299	\$736
Net Working Capital	(\$2,024)	(\$2,024)	(\$1,197)	(\$986)	(\$262)	(\$569)	(\$451)
Notes Payable (Short-Term Debt)	\$2,573	\$2,573	\$1,691	\$1,478	\$675	\$901	\$1,104
Adjusted Short-Term Debt	\$2,024	\$2,024	\$1,197	\$986	\$262	\$569	\$451
Long-Term Debt	\$9,298	\$9,298	\$9,966	\$9,365	\$9,264	\$8,848	\$6,687
Book Value of Long-Term Debt	\$12,211	\$12,211	\$11,618	\$10,757	\$9,995	\$9,716	\$7,874
Unadjusted Market Value of Long Term Debt	\$9,160	\$9,160	\$10,759	\$11,274	\$9,750	\$7,412	\$4,011
Carrying Amount	\$10,345	\$10,345	\$9,687	\$9,627	\$8,998	\$7,342	\$3,688
Adjustment to Book Value of Long-Term Debt	(\$1,185)	(\$1,185)	\$1,071	\$1,647	\$752	\$70	\$323
Market Value of Long-Term Debt	\$11,026	\$11,026	\$12,689	\$12,404	\$10,748	\$9,787	\$8,197
Market Value of Debt	\$11,026	\$11,026	\$12,689	\$12,404	\$10,748	\$9,787	\$8,197
MARKET VALUE OF FIRM							
	\$22,942	\$22,942	\$27,110	\$27,882	\$22,987	\$24,207	\$23,095
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	51.94%	51.94%	53.20%	55.51%	53.25%	59.57%	64.51%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	48.06%	48.06%	46.80%	44.49%	46.75%	40.43%	35.49%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel M: Exelon Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$25,470	\$25,470	\$24,744	\$34,393	\$32,585	\$32,224	\$30,741
Shares Outstanding (in millions) - Common	995	995	979	979	976	976	968
Price per Share - Common	\$37	\$37	\$43	\$39	\$30	\$32	\$33
Market Value of Common Equity	\$36,500	\$36,500	\$41,644	\$38,295	\$29,176	\$31,296	\$31,593
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$36,500	\$36,500	\$41,644	\$38,295	\$29,176	\$31,296	\$31,593
Market to Book Value of Common Equity	1.43	1.43	1.68	1.11	0.90	0.97	1.03
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$7,519	\$7,519	\$7,336	\$13,957	\$12,562	\$12,037	\$13,328
Current Liabilities	\$8,800	\$8,800	\$10,611	\$16,111	\$12,771	\$14,185	\$11,404
Current Portion of Long-Term Debt	\$1,654	\$1,654	\$1,842	\$2,205	\$2,032	\$4,935	\$1,349
Net Working Capital	\$373	\$373	(\$1,433)	\$51	\$1,823	\$2,787	\$3,273
Notes Payable (Short-Term Debt)	\$1,720	\$1,720	\$2,586	\$1,248	\$2,031	\$1,370	\$714
Adjusted Short-Term Debt	\$0	\$0	\$1,433	\$0	\$0	\$0	\$0
Long-Term Debt	\$39,821	\$39,821	\$35,928	\$31,402	\$36,572	\$33,026	\$34,465
Book Value of Long-Term Debt	\$41,475	\$41,475	\$39,203	\$33,607	\$38,604	\$37,961	\$35,814
Unadjusted Market Value of Long Term Debt	\$32,902	\$32,902	\$43,592	\$43,752	\$40,033	\$35,869	\$36,705
Carrying Amount	\$37,074	\$37,074	\$38,697	\$36,912	\$36,039	\$35,424	\$34,264
Adjustment to Book Value of Long-Term Debt	(\$4,172)	(\$4,172)	\$4,895	\$6,840	\$3,994	\$445	\$2,441
Market Value of Long-Term Debt	\$37,303	\$37,303	\$44,098	\$40,447	\$42,598	\$38,406	\$38,255
Market Value of Debt	\$37,303	\$37,303	\$44,098	\$40,447	\$42,598	\$38,406	\$38,255
MARKET VALUE OF FIRM	\$73,803	\$73,803	\$85,742	\$78,742	\$71,774	\$69,702	\$69,848
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	49.46%	49.46%	48.57%	48.63%	40.65%	44.90%	45.23%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	50.54%	50.54%	51.43%	51.37%	59.35%	55.10%	54.77%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel N: IDACORP Inc.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$2,921	\$2,921	\$2,807	\$2,668	\$2,560	\$2,465	\$2,370
Shares Outstanding (in millions) - Common	51	51	51	51	50	50	50
Price per Share - Common	\$98	\$98	\$108	\$111	\$95	\$106	\$97
Market Value of Common Equity	\$4,978	\$4,978	\$5,441	\$5,599	\$4,789	\$5,365	\$4,884
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$4,978	\$4,978	\$5,441	\$5,599	\$4,789	\$5,365	\$4,884
Market to Book Value of Common Equity	1.70	1.70	1.94	2.10	1.87	2.18	2.06
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$1,038	\$1,038	\$694	\$596	\$642	\$565	\$598
Current Liabilities	\$489	\$489	\$549	\$326	\$288	\$375	\$259
Current Portion of Long-Term Debt	\$0	\$0	\$79	\$0	\$0	\$100	\$0
Net Working Capital	\$549	\$549	\$224	\$270	\$355	\$290	\$339
Notes Payable (Short-Term Debt)	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Long-Term Debt	\$2,826	\$2,826	\$2,194	\$2,001	\$2,000	\$1,737	\$1,835
Book Value of Long-Term Debt	\$2,826	\$2,826	\$2,274	\$2,001	\$2,000	\$1,837	\$1,835
Unadjusted Market Value of Long Term Debt	\$1,953	\$1,953	\$2,381	\$2,467	\$2,084	\$1,943	\$1,915
Carrying Amount	\$2,194	\$2,194	\$2,001	\$2,000	\$1,837	\$1,835	\$1,746
Adjustment to Book Value of Long-Term Debt	(\$241)	(\$241)	\$381	\$467	\$247	\$108	\$169
Market Value of Long-Term Debt	\$2,585	\$2,585	\$2,654	\$2,467	\$2,248	\$1,945	\$2,004
Market Value of Debt	\$2,585	\$2,585	\$2,654	\$2,467	\$2,248	\$1,945	\$2,004
MARKET VALUE OF FIRM							
	\$7,563	\$7,563	\$8,095	\$8,067	\$7,037	\$7,310	\$6,888
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	65.81%	65.81%	67.22%	69.41%	68.06%	73.40%	70.90%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	34.19%	34.19%	32.78%	30.59%	31.94%	26.60%	29.10%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel O: MGE Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$1,135	\$1,135	\$1,082	\$1,027	\$976	\$856	\$817
Shares Outstanding (in millions) - Common	36	36	36	36	36	35	35
Price per Share - Common	\$72	\$72	\$71	\$79	\$70	\$79	\$65
Market Value of Common Equity	\$2,620	\$2,620	\$2,575	\$2,864	\$2,545	\$2,728	\$2,242
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$2,620	\$2,620	\$2,575	\$2,864	\$2,545	\$2,728	\$2,242
Market to Book Value of Common Equity	2.31	2.31	2.38	2.79	2.61	3.19	2.75
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$216	\$216	\$243	\$199	\$210	\$182	\$241
Current Liabilities	\$123	\$123	\$225	\$118	\$191	\$129	\$121
Current Portion of Long-Term Debt	\$5	\$5	\$54	\$5	\$5	\$20	\$5
Net Working Capital	\$99	\$99	\$73	\$87	\$24	\$73	\$124
Notes Payable (Short-Term Debt)	\$22	\$22	\$71	\$6	\$53	\$0	\$13
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Long-Term Debt	\$708	\$708	\$610	\$639	\$537	\$541	\$493
Book Value of Long-Term Debt	\$713	\$713	\$665	\$645	\$542	\$561	\$498
Unadjusted Market Value of Long Term Debt	\$571	\$571	\$730	\$639	\$612	\$519	\$475
Carrying Amount	\$644	\$644	\$623	\$528	\$548	\$502	\$427
Adjustment to Book Value of Long-Term Debt	(\$72)	(\$72)	\$106	\$111	\$64	\$16	\$48
Market Value of Long-Term Debt	\$641	\$641	\$771	\$756	\$606	\$577	\$546
Market Value of Debt	\$641	\$641	\$771	\$756	\$606	\$577	\$546
MARKET VALUE OF FIRM							
	\$3,261	\$3,261	\$3,346	\$3,620	\$3,151	\$3,305	\$2,789
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	80.35%	80.35%	76.95%	79.13%	80.77%	82.53%	80.41%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	19.65%	19.65%	23.05%	20.87%	19.23%	17.47%	19.59%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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Prices are reported in Workpaper #1 to Schedule No. D5.6.

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[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel P: NextEra Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$47,468	\$47,468	\$39,229	\$37,202	\$36,513	\$37,005	\$34,144
Shares Outstanding (in millions) - Common	2,024	2,024	1,987	1,963	1,960	1,956	1,912
Price per Share - Common	\$61	\$61	\$85	\$91	\$75	\$60	\$44
Market Value of Common Equity	\$122,776	\$122,776	\$168,133	\$179,344	\$146,588	\$117,074	\$84,212
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$122,776	\$122,776	\$168,133	\$179,344	\$146,588	\$117,074	\$84,212
Market to Book Value of Common Equity	2.59	2.59	4.29	4.82	4.01	3.16	2.47
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$15,361	\$15,361	\$13,490	\$9,288	\$7,382	\$7,408	\$6,393
Current Liabilities	\$27,963	\$27,963	\$26,695	\$17,437	\$15,558	\$13,853	\$17,563
Current Portion of Long-Term Debt	\$6,901	\$6,901	\$6,633	\$1,785	\$4,138	\$2,124	\$2,716
Net Working Capital	(\$5,701)	(\$5,701)	(\$6,572)	(\$6,364)	(\$4,038)	(\$4,321)	(\$8,454)
Notes Payable (Short-Term Debt)	\$4,905	\$4,905	\$3,077	\$2,082	\$2,009	\$2,916	\$8,214
Adjusted Short-Term Debt	\$4,905	\$4,905	\$3,077	\$2,082	\$2,009	\$2,916	\$8,214
Long-Term Debt	\$61,405	\$61,405	\$55,656	\$51,515	\$42,485	\$38,041	\$26,782
Book Value of Long-Term Debt	\$73,211	\$73,211	\$65,366	\$55,382	\$48,632	\$43,081	\$37,712
Unadjusted Market Value of Long Term Debt	\$57,892	\$57,892	\$57,290	\$51,525	\$42,928	\$30,043	\$35,447
Carrying Amount	\$61,889	\$61,889	\$52,745	\$46,082	\$39,667	\$29,498	\$33,134
Adjustment to Book Value of Long-Term Debt	(\$3,997)	(\$3,997)	\$4,545	\$5,443	\$3,261	\$545	\$2,313
Market Value of Long-Term Debt	\$69,214	\$69,214	\$69,911	\$60,825	\$51,893	\$43,626	\$40,025
Market Value of Debt	\$69,214	\$69,214	\$69,911	\$60,825	\$51,893	\$43,626	\$40,025
MARKET VALUE OF FIRM							
	\$191,990	\$191,990	\$238,044	\$240,169	\$198,481	\$160,700	\$124,237
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	63.95%	63.95%	70.63%	74.67%	73.85%	72.85%	67.78%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	36.05%	36.05%	29.37%	25.33%	26.15%	27.15%	32.22%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel Q: NorthWestern Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$2,740	\$2,740	\$2,665	\$2,340	\$2,079	\$2,039	\$1,942
Shares Outstanding (in millions) - Common	61	61	60	54	51	54	54
Price per Share - Common	\$51	\$51	\$58	\$56	\$56	\$71	\$62
Market Value of Common Equity	\$3,151	\$3,151	\$3,469	\$3,027	\$2,855	\$3,857	\$3,329
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$3,151	\$3,151	\$3,469	\$3,027	\$2,855	\$3,857	\$3,329
Market to Book Value of Common Equity	1.15	1.15	1.30	1.29	1.37	1.89	1.71
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$358	\$358	\$539	\$438	\$309	\$302	\$278
Current Liabilities	\$570	\$570	\$621	\$380	\$466	\$334	\$347
Current Portion of Long-Term Debt	\$103	\$103	\$148	\$3	\$3	\$4	\$2
Net Working Capital	(\$108)	(\$108)	\$66	\$61	(\$155)	(\$29)	(\$67)
Notes Payable (Short-Term Debt)	\$0	\$0	\$0	\$0	\$100	\$0	\$0
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$100	\$0	\$0
Long-Term Debt	\$2,551	\$2,551	\$2,483	\$2,553	\$2,330	\$2,253	\$2,122
Book Value of Long-Term Debt	\$2,654	\$2,654	\$2,631	\$2,556	\$2,433	\$2,257	\$2,125
Unadjusted Market Value of Long Term Debt	\$2,317	\$2,317	\$2,827	\$2,630	\$2,417	\$2,118	\$1,902
Carrying Amount	\$2,619	\$2,619	\$2,541	\$2,315	\$2,233	\$2,102	\$1,793
Adjustment to Book Value of Long-Term Debt	(\$302)	(\$302)	\$286	\$314	\$184	\$16	\$108
Market Value of Long-Term Debt	\$2,352	\$2,352	\$2,917	\$2,871	\$2,616	\$2,272	\$2,233
Market Value of Debt	\$2,352	\$2,352	\$2,917	\$2,871	\$2,616	\$2,272	\$2,233
MARKET VALUE OF FIRM	\$5,503	\$5,503	\$6,386	\$5,897	\$5,472	\$6,130	\$5,562
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	57.26%	57.26%	54.32%	51.32%	52.19%	62.93%	59.85%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	42.74%	42.74%	45.68%	48.68%	47.81%	37.07%	40.15%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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(1): 0 if [m] > 0.

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(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel R: OGE Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$4,541	\$4,541	\$4,413	\$4,056	\$3,632	\$4,140	\$4,005
Shares Outstanding (in millions) - Common	200	200	200	200	200	200	200
Price per Share - Common	\$35	\$35	\$40	\$37	\$32	\$44	\$40
Market Value of Common Equity	\$7,074	\$7,074	\$7,979	\$7,442	\$6,305	\$8,765	\$8,003
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$7,074	\$7,074	\$7,979	\$7,442	\$6,305	\$8,765	\$8,003
Market to Book Value of Common Equity	1.56	1.56	1.81	1.83	1.74	2.12	2.00
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$905	\$905	\$1,341	\$614	\$429	\$430	\$557
Current Liabilities	\$1,108	\$1,108	\$1,802	\$1,090	\$697	\$658	\$869
Current Portion of Long-Term Debt	\$0	\$0	\$1,006	\$6	\$6	\$6	\$250
Net Working Capital	(\$202)	(\$202)	\$544	(\$470)	(\$263)	(\$222)	(\$62)
Notes Payable (Short-Term Debt)	\$411	\$411	\$0	\$487	\$95	\$112	\$0
Adjusted Short-Term Debt	\$202	\$202	\$0	\$470	\$95	\$112	\$0
Long-Term Debt	\$4,340	\$4,340	\$3,578	\$4,528	\$3,531	\$3,235	\$2,897
Book Value of Long-Term Debt	\$4,542	\$4,542	\$4,583	\$5,004	\$3,632	\$3,353	\$3,147
Unadjusted Market Value of Long Term Debt	\$4,161	\$4,161	\$5,103	\$4,328	\$3,646	\$3,322	\$3,388
Carrying Amount	\$4,549	\$4,549	\$4,496	\$3,494	\$3,195	\$3,147	\$2,999
Adjustment to Book Value of Long-Term Debt	(\$388)	(\$388)	\$607	\$834	\$451	\$175	\$389
Market Value of Long-Term Debt	\$4,155	\$4,155	\$5,190	\$5,838	\$4,082	\$3,528	\$3,536
Market Value of Debt	\$4,155	\$4,155	\$5,190	\$5,838	\$4,082	\$3,528	\$3,536
MARKET VALUE OF FIRM							
	\$11,229	\$11,229	\$13,169	\$13,280	\$10,387	\$12,293	\$11,538
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	63.00%	63.00%	60.59%	56.04%	60.70%	71.30%	69.36%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	37.00%	37.00%	39.41%	43.96%	39.30%	28.70%	30.64%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel S: Otter Tail Corp.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$1,443	\$1,443	\$1,217	\$991	\$871	\$781	\$729
Shares Outstanding (in millions) - Common	42	42	42	42	41	40	40
Price per Share - Common	\$82	\$82	\$59	\$69	\$43	\$51	\$50
Market Value of Common Equity	\$3,428	\$3,428	\$2,436	\$2,857	\$1,772	\$2,058	\$1,972
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$3,428	\$3,428	\$2,436	\$2,857	\$1,772	\$2,058	\$1,972
Market to Book Value of Common Equity	2.38	2.38	2.00	2.88	2.04	2.63	2.71
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$570	\$570	\$453	\$369	\$235	\$255	\$241
Current Liabilities	\$310	\$310	\$238	\$388	\$437	\$190	\$170
Current Portion of Long-Term Debt	\$5	\$5	\$5	\$34	\$145	\$4	\$0
Net Working Capital	\$265	\$265	\$220	\$16	(\$57)	\$69	\$71
Notes Payable (Short-Term Debt)	\$81	\$81	\$8	\$91	\$81	\$6	\$19
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$57	\$0	\$0
Long-Term Debt	\$824	\$824	\$838	\$749	\$640	\$708	\$590
Book Value of Long-Term Debt	\$829	\$829	\$843	\$783	\$842	\$712	\$590
Unadjusted Market Value of Long Term Debt	\$682	\$682	\$878	\$858	\$742	\$602	\$543
Carrying Amount	\$824	\$824	\$764	\$765	\$690	\$590	\$491
Adjustment to Book Value of Long-Term Debt	(\$142)	(\$142)	\$114	\$94	\$53	\$11	\$52
Market Value of Long-Term Debt	\$687	\$687	\$957	\$877	\$894	\$723	\$642
Market Value of Debt	\$687	\$687	\$957	\$877	\$894	\$723	\$642
MARKET VALUE OF FIRM	\$4,115	\$4,115	\$3,394	\$3,734	\$2,667	\$2,782	\$2,615
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	83.31%	83.31%	71.80%	76.50%	66.46%	73.99%	75.43%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	16.69%	16.69%	28.20%	23.50%	33.54%	26.01%	24.57%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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Prices are reported in Workpaper #1 to Schedule No. D5.6.

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[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel T: Pinnacle West Capital

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$6,375	\$6,375	\$6,049	\$5,906	\$5,634	\$5,431	\$5,223
Shares Outstanding (in millions) - Common	113	113	113	113	113	112	112
Price per Share - Common	\$73	\$73	\$78	\$68	\$79	\$88	\$89
Market Value of Common Equity	\$8,270	\$8,270	\$8,799	\$7,729	\$8,888	\$9,899	\$9,925
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$8,270	\$8,270	\$8,799	\$7,729	\$8,888	\$9,899	\$9,925
Market to Book Value of Common Equity	1.30	1.30	1.45	1.31	1.58	1.82	1.90
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$2,162	\$2,162	\$1,751	\$1,551	\$1,198	\$1,030	\$925
Current Liabilities	\$1,968	\$1,968	\$1,762	\$1,757	\$1,360	\$2,078	\$1,649
Current Portion of Long-Term Debt	\$341	\$341	\$156	\$250	\$75	\$813	\$500
Net Working Capital	\$534	\$534	\$144	\$45	(\$87)	(\$236)	(\$224)
Notes Payable (Short-Term Debt)	\$424	\$424	\$341	\$292	\$169	\$115	\$76
Adjusted Short-Term Debt	\$0	\$0	\$0	\$0	\$87	\$115	\$76
Long-Term Debt	\$9,369	\$9,369	\$8,381	\$7,642	\$6,676	\$4,884	\$4,638
Book Value of Long-Term Debt	\$9,710	\$9,710	\$8,536	\$7,893	\$6,838	\$5,812	\$5,215
Unadjusted Market Value of Long Term Debt	\$6,586	\$6,586	\$7,726	\$7,613	\$6,194	\$5,234	\$5,305
Carrying Amount	\$7,792	\$7,792	\$7,064	\$6,314	\$5,633	\$5,138	\$4,872
Adjustment to Book Value of Long-Term Debt	(\$1,206)	(\$1,206)	\$663	\$1,299	\$562	\$95	\$433
Market Value of Long-Term Debt	\$8,503	\$8,503	\$9,199	\$9,191	\$7,400	\$5,907	\$5,648
Market Value of Debt	\$8,503	\$8,503	\$9,199	\$9,191	\$7,400	\$5,907	\$5,648
MARKET VALUE OF FIRM	\$16,773	\$16,773	\$17,998	\$16,921	\$16,288	\$15,806	\$15,573
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	49.30%	49.30%	48.89%	45.68%	54.57%	62.63%	63.73%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	50.70%	50.70%	51.11%	54.32%	45.43%	37.37%	36.27%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel U: Public Serv. Enterprise

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$15,166	\$15,166	\$13,729	\$14,438	\$15,984	\$15,089	\$14,377
Shares Outstanding (in millions) - Common	498	498	497	504	504	504	504
Price per Share - Common	\$62	\$62	\$61	\$65	\$57	\$59	\$53
Market Value of Common Equity	\$30,750	\$30,750	\$30,110	\$32,794	\$28,731	\$29,575	\$26,823
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$30,750	\$30,750	\$30,110	\$32,794	\$28,731	\$29,575	\$26,823
Market to Book Value of Common Equity	2.03	2.03	2.19	2.27	1.80	1.96	1.87
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$3,283	\$3,283	\$4,303	\$6,250	\$3,630	\$3,231	\$3,507
Current Liabilities	\$5,190	\$5,190	\$6,680	\$7,072	\$5,522	\$5,047	\$4,935
Current Portion of Long-Term Debt	\$2,000	\$2,000	\$1,575	\$700	\$1,684	\$1,398	\$1,294
Net Working Capital	\$93	\$93	(\$802)	(\$122)	(\$208)	(\$418)	(\$134)
Notes Payable (Short-Term Debt)	\$695	\$695	\$2,200	\$3,519	\$1,063	\$1,115	\$1,016
Adjusted Short-Term Debt	\$0	\$0	\$802	\$122	\$208	\$418	\$134
Long-Term Debt	\$17,212	\$17,212	\$16,664	\$15,410	\$14,748	\$14,016	\$13,168
Book Value of Long-Term Debt	\$19,212	\$19,212	\$19,041	\$16,232	\$16,640	\$15,832	\$14,596
Unadjusted Market Value of Long Term Debt	\$16,164	\$16,164	\$17,546	\$19,143	\$16,723	\$14,767	\$14,062
Carrying Amount	\$18,070	\$18,070	\$15,919	\$16,180	\$15,108	\$14,462	\$13,068
Adjustment to Book Value of Long-Term Debt	(\$1,906)	(\$1,906)	\$1,627	\$2,963	\$1,615	\$305	\$994
Market Value of Long-Term Debt	\$17,306	\$17,306	\$20,668	\$19,195	\$18,255	\$16,137	\$15,590
Market Value of Debt	\$17,306	\$17,306	\$20,668	\$19,195	\$18,255	\$16,137	\$15,590
MARKET VALUE OF FIRM	\$48,056	\$48,056	\$50,778	\$51,989	\$46,986	\$45,712	\$42,413
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	63.99%	63.99%	59.30%	63.08%	61.15%	64.70%	63.24%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	36.01%	36.01%	40.70%	36.92%	38.85%	35.30%	36.76%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

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Prices are reported in Workpaper #1 to Schedule No. D5.6.

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(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel V: Sempra Energy

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$27,349	\$27,349	\$26,226	\$25,092	\$20,226	\$17,671	\$14,880
Shares Outstanding (in millions) - Common	315	315	628	634	576	584	548
Price per Share - Common	\$74	\$74	\$80	\$64	\$64	\$75	\$56
Market Value of Common Equity	\$23,414	\$23,414	\$49,931	\$40,860	\$36,830	\$43,877	\$30,908
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$23,414	\$23,414	\$49,931	\$40,860	\$36,830	\$43,877	\$30,908
Market to Book Value of Common Equity	0.86	0.86	1.90	1.63	1.82	2.48	2.08
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$909	\$909	\$909	\$909	\$3,167	\$2,278	\$2,278
Market Value of Preferred Equity	\$909	\$909	\$909	\$909	\$3,167	\$2,278	\$2,278
MARKET VALUE OF DEBT							
Current Assets	\$5,310	\$5,310	\$5,912	\$4,375	\$4,511	\$3,339	\$3,645
Current Liabilities	\$8,765	\$8,765	\$9,899	\$10,035	\$6,839	\$9,150	\$7,523
Current Portion of Long-Term Debt	\$974	\$974	\$1,072	\$155	\$1,592	\$1,578	\$1,644
Net Working Capital	(\$2,481)	(\$2,481)	(\$2,915)	(\$5,505)	(\$736)	(\$4,233)	(\$2,234)
Notes Payable (Short-Term Debt)	\$1,977	\$1,977	\$3,352	\$3,471	\$885	\$3,505	\$2,024
Adjusted Short-Term Debt	\$1,977	\$1,977	\$2,915	\$3,471	\$736	\$3,505	\$2,024
Long-Term Debt	\$27,703	\$27,703	\$25,076	\$21,538	\$22,188	\$21,230	\$22,327
Book Value of Long-Term Debt	\$30,654	\$30,654	\$29,063	\$25,164	\$24,516	\$26,313	\$25,995
Unadjusted Market Value of Long Term Debt	\$21,549	\$21,549	\$22,126	\$25,478	\$10,003	\$7,086	\$7,153
Carrying Amount	\$24,513	\$24,513	\$20,099	\$22,259	\$8,625	\$6,435	\$6,117
Adjustment to Book Value of Long-Term Debt	(\$2,964)	(\$2,964)	\$2,027	\$3,219	\$1,378	\$651	\$1,036
Market Value of Long-Term Debt	\$27,690	\$27,690	\$31,090	\$28,383	\$25,894	\$26,964	\$27,031
Market Value of Debt	\$27,690	\$27,690	\$31,090	\$28,383	\$25,894	\$26,964	\$27,031
MARKET VALUE OF FIRM							
	\$52,013	\$52,013	\$81,930	\$70,152	\$65,891	\$73,119	\$60,217
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	45.02%	45.02%	60.94%	58.25%	55.90%	60.01%	51.33%
Preferred Equity - Market Value Ratio	1.75%	1.75%	1.11%	1.30%	4.81%	3.12%	3.78%
Debt - Market Value Ratio	53.24%	53.24%	37.95%	40.46%	39.30%	36.88%	44.89%

Sources and Notes:

Bloomberg as of December 31, 2023

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(1): 0 if [m] > 0.

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(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel W: Southern Co.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$31,377	\$31,377	\$30,408	\$27,874	\$27,972	\$27,505	\$24,723
Shares Outstanding (in millions) - Common	1,091	1,091	1,099	1,099	1,099	1,099	999
Price per Share - Common	\$71	\$71	\$71	\$67	\$60	\$63	\$45
Market Value of Common Equity	\$77,031	\$77,031	\$77,710	\$73,616	\$66,239	\$68,803	\$45,431
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$77,031	\$77,031	\$77,710	\$73,616	\$66,239	\$68,803	\$45,431
Market to Book Value of Common Equity	2.46	2.46	2.56	2.64	2.37	2.50	1.84
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$291	\$291	\$291	\$291
Market Value of Preferred Equity	\$0	\$0	\$0	\$291	\$291	\$291	\$291
MARKET VALUE OF DEBT							
Current Assets	\$11,088	\$11,088	\$10,416	\$8,965	\$8,617	\$9,817	\$9,583
Current Liabilities	\$13,214	\$13,214	\$15,724	\$10,921	\$12,079	\$12,546	\$14,286
Current Portion of Long-Term Debt	\$3,257	\$3,257	\$4,482	\$2,407	\$3,748	\$3,218	\$3,198
Net Working Capital	\$1,131	\$1,131	(\$826)	\$451	\$286	\$489	(\$1,505)
Notes Payable (Short-Term Debt)	\$1,726	\$1,726	\$2,609	\$1,440	\$609	\$2,055	\$2,915
Adjusted Short-Term Debt	\$0	\$0	\$826	\$0	\$0	\$0	\$1,505
Long-Term Debt	\$57,323	\$57,323	\$52,044	\$51,623	\$46,684	\$43,413	\$40,736
Book Value of Long-Term Debt	\$60,580	\$60,580	\$57,352	\$54,030	\$50,432	\$46,631	\$45,439
Unadjusted Market Value of Long Term Debt	\$48,600	\$48,600	\$57,100	\$56,264	\$48,339	\$44,824	\$51,348
Carrying Amount	\$54,600	\$54,600	\$52,100	\$48,349	\$44,561	\$45,023	\$48,151
Adjustment to Book Value of Long-Term Debt	(\$6,000)	(\$6,000)	\$5,000	\$7,915	\$3,778	(\$199)	\$3,197
Market Value of Long-Term Debt	\$54,580	\$54,580	\$62,352	\$61,945	\$54,210	\$46,432	\$48,636
Market Value of Debt	\$54,580	\$54,580	\$62,352	\$61,945	\$54,210	\$46,432	\$48,636
MARKET VALUE OF FIRM							
	\$131,611	\$131,611	\$140,062	\$135,852	\$120,740	\$115,526	\$94,358
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	58.53%	58.53%	55.48%	54.19%	54.86%	59.56%	48.15%
Preferred Equity - Market Value Ratio	-	-	-	0.21%	0.24%	0.25%	0.31%
Debt - Market Value Ratio	41.47%	41.47%	44.52%	45.60%	44.90%	40.19%	51.54%

Sources and Notes:

Bloomberg as of December 31, 2023

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(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel X: WEC Energy Group

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$11,724	\$11,724	\$11,377	\$10,913	\$10,470	\$10,113	\$9,789
Shares Outstanding (in millions) - Common	315	315	315	315	315	315	316
Price per Share - Common	\$84	\$84	\$96	\$96	\$91	\$91	\$72
Market Value of Common Equity	\$26,358	\$26,358	\$30,193	\$30,246	\$28,716	\$28,739	\$22,598
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$26,358	\$26,358	\$30,193	\$30,246	\$28,716	\$28,739	\$22,598
Market to Book Value of Common Equity	2.25	2.25	2.65	2.77	2.74	2.84	2.31
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$30	\$30	\$30	\$30	\$30	\$30	\$30
Market Value of Preferred Equity	\$30	\$30	\$30	\$30	\$30	\$30	\$30
MARKET VALUE OF DEBT							
Current Assets	\$2,796	\$2,796	\$3,188	\$2,657	\$2,083	\$2,094	\$2,248
Current Liabilities	\$5,115	\$5,115	\$4,611	\$3,753	\$4,148	\$3,183	\$3,332
Current Portion of Long-Term Debt	\$1,264	\$1,264	\$885	\$173	\$789	\$698	\$365
Net Working Capital	(\$1,055)	(\$1,055)	(\$538)	(\$923)	(\$1,276)	(\$392)	(\$719)
Notes Payable (Short-Term Debt)	\$2,021	\$2,021	\$1,647	\$1,897	\$1,777	\$831	\$1,440
Adjusted Short-Term Debt	\$1,055	\$1,055	\$538	\$923	\$1,276	\$392	\$719
Long-Term Debt	\$15,513	\$15,513	\$14,792	\$13,553	\$11,761	\$11,248	\$9,994
Book Value of Long-Term Debt	\$17,832	\$17,832	\$16,215	\$14,649	\$13,826	\$12,337	\$11,078
Unadjusted Market Value of Long Term Debt	\$13,921	\$13,921	\$14,819	\$14,343	\$13,036	\$10,555	\$10,342
Carrying Amount	\$15,464	\$15,464	\$13,563	\$12,451	\$11,858	\$10,336	\$9,562
Adjustment to Book Value of Long-Term Debt	(\$1,543)	(\$1,543)	\$1,256	\$1,893	\$1,178	\$219	\$780
Market Value of Long-Term Debt	\$16,289	\$16,289	\$17,471	\$16,542	\$15,003	\$12,556	\$11,858
Market Value of Debt	\$16,289	\$16,289	\$17,471	\$16,542	\$15,003	\$12,556	\$11,858
MARKET VALUE OF FIRM							
	\$42,678	\$42,678	\$47,694	\$46,818	\$43,749	\$41,326	\$34,487
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	61.76%	61.76%	63.31%	64.60%	65.64%	69.54%	65.53%
Preferred Equity - Market Value Ratio	0.07%	0.07%	0.06%	0.06%	0.07%	0.07%	0.09%
Debt - Market Value Ratio	38.17%	38.17%	36.63%	35.33%	34.29%	30.38%	34.38%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.3

Market Value of the Electric Sample

Panel Y: Xcel Energy Inc.

(\$MM)

	DCF Capital Structure	Year End, 2023	Year End, 2022	Year End, 2021	Year End, 2020	Year End, 2019	Year End, 2018
MARKET VALUE OF COMMON EQUITY	DCF Capital Structure	12/31/23	12/31/22	12/31/21	12/31/20	12/31/19	12/31/18
Book Value, Common Shareholder's Equity	\$35,232	\$35,232	\$16,675	\$15,612	\$14,575	\$13,239	\$12,222
Shares Outstanding (in millions) - Common	552	552	550	550	537	525	514
Price per Share - Common	\$62	\$62	\$71	\$67	\$65	\$63	\$51
Market Value of Common Equity	\$34,132	\$34,132	\$38,778	\$37,051	\$35,190	\$33,026	\$26,368
Market Value of GP Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Market Value of Equity	\$34,132	\$34,132	\$38,778	\$37,051	\$35,190	\$33,026	\$26,368
Market to Book Value of Common Equity	0.97	0.97	2.33	2.37	2.41	2.49	2.16
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Market Value of Preferred Equity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
MARKET VALUE OF DEBT							
Current Assets	\$4,402	\$4,402	\$5,144	\$4,239	\$3,275	\$3,113	\$3,094
Current Liabilities	\$1,337	\$1,337	\$6,078	\$5,046	\$4,239	\$4,568	\$4,460
Current Portion of Long-Term Debt	\$552	\$552	\$1,368	\$806	\$635	\$900	\$406
Net Working Capital	\$3,617	\$3,617	\$434	(\$1)	(\$329)	(\$555)	(\$960)
Notes Payable (Short-Term Debt)	\$785	\$785	\$813	\$1,005	\$584	\$595	\$1,038
Adjusted Short-Term Debt	\$0	\$0	\$0	\$1	\$329	\$555	\$960
Long-Term Debt	\$24,913	\$24,913	\$23,851	\$22,925	\$20,989	\$19,033	\$15,888
Book Value of Long-Term Debt	\$25,465	\$25,465	\$25,219	\$23,732	\$21,953	\$20,488	\$17,254
Unadjusted Market Value of Long Term Debt	\$20,897	\$20,897	\$25,232	\$24,412	\$20,227	\$16,755	\$16,531
Carrying Amount	\$23,964	\$23,964	\$22,380	\$20,066	\$18,109	\$16,209	\$14,977
Adjustment to Book Value of Long-Term Debt	(\$3,067)	(\$3,067)	\$2,852	\$4,346	\$2,118	\$546	\$1,554
Market Value of Long-Term Debt	\$22,398	\$22,398	\$28,071	\$28,078	\$24,071	\$21,034	\$18,808
Market Value of Debt	\$22,398	\$22,398	\$28,071	\$28,078	\$24,071	\$21,034	\$18,808
MARKET VALUE OF FIRM	\$56,530	\$56,530	\$66,849	\$65,129	\$59,261	\$54,060	\$45,176
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	60.38%	60.38%	58.01%	56.89%	59.38%	61.09%	58.37%
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-
Debt - Market Value Ratio	39.62%	39.62%	41.99%	43.11%	40.62%	38.91%	41.63%

Sources and Notes:

Bloomberg as of December 31, 2023

Capital structure from Year End, 2023 calculated using respective balance sheet information and 15-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2023 balance sheet information and a 15-trading day average closing price ending on 12/31/2023.

Prices are reported in Workpaper #1 to Schedule No. D5.6.

[e] = Market Value of GP equity is not estimated here.

[o] =

(1): 0 if [m] > 0.

(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].

(3): [n] if [m] < 0 and |[m]| > [n].

[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2018 to 2022 10-Ks.

Schedule No. D5.4

Electric Sample

Capital Structure Summary of the Electric Sample

Company	DCF Capital Structure			5-Year Average Capital Structure		
	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	0.68	0.00	0.32	0.32	0.00	0.18
Alliant Energy	0.61	0.00	0.39	0.62	0.01	0.38
Amer. Elec. Power	0.53	0.00	0.47	0.54	0.00	0.46
Ameren Corp.	0.58	0.00	0.42	0.61	0.00	0.39
Avista Corp.	0.52	0.00	0.48	0.54	0.00	0.46
Black Hills	0.45	0.00	0.55	0.50	0.00	0.50
CMS Energy Corp.	0.55	0.01	0.44	0.55	0.00	0.44
CenterPoint Energy	0.54	0.00	0.46	0.49	0.04	0.47
Duke Energy	0.45	0.01	0.53	0.50	0.01	0.49
Edison Int'l	0.43	0.06	0.50	0.46	0.05	0.49
Entergy Corp.	0.48	0.01	0.51	0.47	0.01	0.52
Evergy Inc.	0.52	0.00	0.48	0.56	0.00	0.44
Exelon Corp.	0.49	0.00	0.51	0.46	0.00	0.54
IDACORP Inc.	0.66	0.00	0.34	0.69	0.00	0.31
MGE Energy	0.80	0.00	0.20	0.80	0.00	0.20
NextEra Energy	0.64	0.00	0.36	0.72	0.00	0.28
NorthWestern Corp.	0.57	0.00	0.43	0.56	0.00	0.44
OGE Energy	0.63	0.00	0.37	0.63	0.00	0.37
Otter Tail Corp.	0.83	0.00	0.17	0.74	0.00	0.26
Pinnacle West Capital	0.49	0.00	0.51	0.54	0.00	0.46
Public Serv. Enterprise	0.64	0.00	0.36	0.62	0.00	0.38
Sempra Energy	0.45	0.02	0.53	0.57	0.03	0.41
Southern Co.	0.59	0.00	0.41	0.55	0.00	0.44
WEC Energy Group	0.62	0.00	0.38	0.65	0.00	0.35
Xcel Energy Inc.	0.60	0.00	0.40	0.59	0.00	0.41
Electric Sample Average	0.57	0.00	0.42	0.57	0.01	0.40

Sources and Notes:

[1], [4]:Workpaper #1 to Schedule No. D5.4.

[2], [5]:Workpaper #2 to Schedule No. D5.4.

[3], [6]:Workpaper #3 to Schedule No. D5.4.

Values in this table may not add up exactly to 1.0 because of rounding.

Schedule No. D5.5

Electric Sample

Estimated Growth Rates of the Electric Sample

Company	Thomson Reuters IBES Estimate		Value Line		Annualized Growth Rate	Combined Growth Rate
	Long-Term Growth Rate	Number of Estimates	EPS Year 2023 Estimate	EPS Year 2026-2028 Estimate		
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	8.1%	1	4.35	5.00	3.5%	5.8%
Alliant Energy	6.7%	2	2.85	3.80	7.5%	6.9%
Amer. Elec. Power	3.7%	1	5.25	6.80	6.7%	5.2%
Ameren Corp.	5.4%	1	4.40	5.50	5.7%	5.6%
Avista Corp.	5.9%	1	2.30	2.90	6.0%	5.9%
Black Hills	n/a	n/a	3.75	4.50	4.7%	4.7%
CMS Energy Corp.	7.7%	2	3.05	3.75	5.3%	6.9%
CenterPoint Energy	n/a	n/a	1.73	2.10	5.0%	5.0%
Duke Energy	6.7%	2	5.60	7.00	5.7%	6.4%
Edison Int'l	4.9%	4	4.75	6.00	6.0%	5.1%
Entergy Corp.	n/a	n/a	7.25	7.50	0.9%	0.9%
Eversource Inc.	2.5%	1	3.60	4.85	7.7%	5.1%
Exelon Corp.	10.1%	3	2.40	3.00	5.7%	9.0%
IDACORP Inc.	n/a	n/a	5.15	6.10	4.3%	4.3%
MGE Energy	n/a	n/a	3.35	4.00	4.5%	4.5%
NextEra Energy	8.2%	2	3.20	4.40	8.3%	8.2%
NorthWestern Corp.	4.1%	3	3.45	4.15	4.7%	4.2%
OGE Energy	n/a	n/a	2.05	3.15	11.3%	11.3%
Otter Tail Corp.	n/a	n/a	6.40	3.65	-13.1%	-13.1%
Pinnacle West Capital	5.9%	2	4.20	5.70	7.9%	6.6%
Public Serv. Enterprise	5.2%	2	3.50	4.40	5.9%	5.4%
Sempra Energy	n/a	n/a	4.50	6.00	7.5%	7.5%
Southern Co.	7.1%	2	3.60	5.15	9.4%	7.9%
WEC Energy Group	5.5%	2	4.60	5.90	6.4%	5.8%
Xcel Energy Inc.	6.3%	2	3.35	4.25	6.1%	6.2%

Sources and Notes:

[1] - [2]: Thomson Reuters as of December 31, 2023.

[3] - [4]: From Valueline Investment Analyzer as of December 31, 2023.

[5]: $(([4] / [3])^{1/4}) - 1$.

[6]: $(([1] \times [2] + [5]) / ([2] + 1))$.

Weighted average growth rate. If information is missing from one source, the weighted average is based solely on the other source.

Schedule No. D5.6

DCF Cost of Equity of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price	Most Recent Dividend	Quarterly Dividend Yield (t+1)	Combined Long-Term Growth Rate	Quarterly Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	\$61.03	\$0.68	1.13%	5.8%	1.4%	10.6%
Alliant Energy	\$51.25	\$0.45	0.90%	6.9%	1.7%	10.7%
Amer. Elec. Power	\$81.20	\$0.88	1.10%	5.2%	1.3%	9.8%
Ameren Corp.	\$74.00	\$0.63	0.86%	5.6%	1.4%	9.2%
Avista Corp.	\$35.47	\$0.46	1.32%	5.9%	1.5%	11.5%
Black Hills	\$54.42	\$0.63	1.16%	4.7%	1.1%	9.6%
CMS Energy Corp.	\$57.96	\$0.49	0.86%	6.9%	1.7%	10.5%
CenterPoint Energy	\$28.82	\$0.20	0.70%	5.0%	1.2%	7.9%
Duke Energy	\$96.53	\$1.03	1.08%	6.4%	1.6%	11.0%
Edison Int'l	\$69.85	\$0.78	1.13%	5.1%	1.2%	9.9%
Entergy Corp.	\$101.38	\$1.13	1.12%	0.9%	0.2%	5.4%
Evergy Inc.	\$51.87	\$0.64	1.25%	5.1%	1.3%	10.4%
Exelon Corp.	\$36.68	\$0.36	1.00%	9.0%	2.2%	13.4%
IDACORP Inc.	\$98.34	\$0.83	0.85%	4.3%	1.1%	7.9%
MGE Energy	\$72.46	\$0.43	0.60%	4.5%	1.1%	7.0%
NextEra Energy	\$60.67	\$0.47	0.79%	8.2%	2.0%	11.6%
NorthWestern Corp.	\$51.46	\$0.64	1.26%	4.2%	1.0%	9.5%
OGE Energy	\$35.32	\$0.42	1.22%	11.3%	2.7%	16.7%
Otter Tail Corp.	\$82.19	\$0.44	0.51%	-13.1%	-3.4%	-11.2%
Pinnacle West Capital	\$72.96	\$0.88	1.23%	6.6%	1.6%	11.8%
Public Serv. Enterprise	\$61.75	\$0.57	0.94%	5.4%	1.3%	9.4%
Sempra Energy	\$74.41	\$0.60	0.81%	7.5%	1.8%	10.9%
Southern Co.	\$70.61	\$0.70	1.01%	7.9%	1.9%	12.2%
WEC Energy Group	\$83.56	\$0.78	0.95%	5.8%	1.4%	9.8%
Xcel Energy Inc.	\$61.87	\$0.52	0.85%	6.2%	1.5%	9.9%

Sources and Notes:

[1]: Workpaper #1 to Schedule No. D5.6.

[2]: Workpaper #2 to Schedule No. D5.6.

[3]: $\{([2] / [1]) \times (1 + [5])\}$.

[4]: Schedule No. D5.5, [6].

[5]: $\{(1 + [4])^{(1/4)} - 1\}$.

[6]: $\{([3] + [5] + 1)^{1/4} - 1\}$.

Schedule No. D5.6

DCF Cost of Equity of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price	Most Recent Dividend	Combined Long-Term Growth Rate	Growth Rate: Year 6	Growth Rate: Year 7	Growth Rate: Year 8	Growth Rate: Year 9	Growth Rate: Year 10	GDP Long-Term Growth Rate	DCF Cost of Equity
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	\$61.03	\$0.68	5.8%	5.5%	5.2%	4.9%	4.6%	4.3%	4.0%	9.2%
Alliant Energy	\$51.25	\$0.45	6.9%	6.4%	5.9%	5.5%	5.0%	4.5%	4.0%	8.5%
Amer. Elec. Power	\$81.20	\$0.88	5.2%	5.0%	4.8%	4.6%	4.4%	4.2%	4.0%	8.9%
Ameren Corp.	\$74.00	\$0.63	5.6%	5.3%	5.0%	4.8%	4.5%	4.3%	4.0%	8.0%
Avista Corp.	\$35.47	\$0.46	5.9%	5.6%	5.3%	5.0%	4.6%	4.3%	4.0%	10.2%
Black Hills	\$54.42	\$0.63	4.7%	4.6%	4.4%	4.3%	4.2%	4.1%	4.0%	9.1%
CMS Energy Corp.	\$57.96	\$0.49	6.9%	6.4%	5.9%	5.5%	5.0%	4.5%	4.0%	8.3%
CenterPoint Energy	\$28.82	\$0.20	5.0%	4.8%	4.6%	4.5%	4.3%	4.2%	4.0%	7.1%
Duke Energy	\$96.53	\$1.03	6.4%	6.0%	5.6%	5.2%	4.8%	4.4%	4.0%	9.2%
Edison Int'l	\$69.85	\$0.78	5.1%	4.9%	4.7%	4.5%	4.4%	4.2%	4.0%	9.0%
Entergy Corp.	\$101.38	\$1.13	0.9%	1.4%	1.9%	2.4%	3.0%	3.5%	4.0%	7.9%
Evergy Inc.	\$51.87	\$0.64	5.1%	4.9%	4.7%	4.6%	4.4%	4.2%	4.0%	9.6%
Exelon Corp.	\$36.68	\$0.36	9.0%	8.2%	7.3%	6.5%	5.7%	4.8%	4.0%	9.6%
IDACORP Inc.	\$98.34	\$0.83	4.3%	4.3%	4.2%	4.2%	4.1%	4.1%	4.0%	7.6%
MGE Energy	\$72.46	\$0.43	4.5%	4.4%	4.4%	4.3%	4.2%	4.1%	4.0%	6.6%
NextEra Energy	\$60.67	\$0.47	8.2%	7.5%	6.8%	6.1%	5.4%	4.7%	4.0%	8.2%
NorthWestern Corp.	\$51.46	\$0.64	4.2%	4.2%	4.2%	4.1%	4.1%	4.0%	4.0%	9.3%
OGE Energy	\$35.32	\$0.42	11.3%	10.1%	8.9%	7.7%	6.4%	5.2%	4.0%	11.6%
Otter Tail Corp.	\$82.19	\$0.44	-13.1%	-10.2%	-7.4%	-4.5%	-1.7%	1.2%	4.0%	4.6%
Pinnacle West Capital	\$72.96	\$0.88	6.6%	6.1%	5.7%	5.3%	4.9%	4.4%	4.0%	10.0%
Public Serv. Enterprise	\$61.75	\$0.57	5.4%	5.2%	5.0%	4.7%	4.5%	4.2%	4.0%	8.3%
Sempra Energy	\$74.41	\$0.60	7.5%	6.9%	6.3%	5.7%	5.2%	4.6%	4.0%	8.2%
Southern Co.	\$70.61	\$0.70	7.9%	7.2%	6.6%	5.9%	5.3%	4.6%	4.0%	9.3%
WEC Energy Group	\$83.56	\$0.78	5.8%	5.5%	5.2%	4.9%	4.6%	4.3%	4.0%	8.4%
Xcel Energy Inc.	\$61.87	\$0.52	6.2%	5.9%	5.5%	5.1%	4.7%	4.4%	4.0%	8.1%

Sources and Notes:

[1]: Workpaper #1 to Schedule No. D5.6.
[2]: Workpaper #2 to Schedule No. D5.6.
[3]: Schedule No. D5.5, [6].
[4]: [3] - ((([3] - [9])/ 6).
[5]: [4] - ((([3] - [9])/ 6).

[6]: [5] - ((([3] - [9])/ 6).
[7]: [6] - ((([3] - [9])/ 6).
[8]: [7] - ((([3] - [9])/ 6).
[9]: BlueChip Economic Indicators, October 2023 This number is assumed to be the perpetual growth rate.
[10]: Workpaper #3 to Schedule No. D5.6.

Schedule No. D5.7

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	4th Quarter, 2023 S&P Bond Rating	4th Quarter, 2023 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	DTE Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	BBB	-	10.6%	0.68	-	0.00	5.7%	0.32	25.7%	8.5%
Alliant Energy	A	-	10.7%	0.61	-	0.00	5.4%	0.39	25.7%	8.1%
Amer. Elec. Power	A	-	9.8%	0.53	-	0.00	5.4%	0.47	25.7%	7.1%
Ameren Corp.	BBB	-	9.2%	0.58	-	0.00	5.7%	0.42	25.7%	7.1%
Avista Corp.	BBB	-	11.5%	0.52	-	0.00	5.7%	0.48	25.7%	8.0%
Black Hills	BBB	-	9.6%	0.45	-	0.00	5.7%	0.55	25.7%	6.6%
CMS Energy Corp.	BBB	BBB	10.5%	0.55	5.7%	0.01	5.7%	0.44	25.7%	7.7%
CenterPoint Energy	BBB	-	7.9%	0.54	-	0.00	5.7%	0.46	25.7%	6.2%
Duke Energy	BBB	BBB	11.0%	0.45	5.7%	0.01	5.7%	0.53	25.7%	7.3%
Edison Int'l	BBB	BBB	9.9%	0.43	5.7%	0.06	5.7%	0.50	25.7%	6.8%
Entergy Corp.	BBB	BBB	~~5.4%~~	0.48	5.7%	0.01	5.7%	0.51	25.7%	~~4.8%~~
Evergy Inc.	BBB	-	10.4%	0.52	-	0.00	5.7%	0.48	25.7%	7.4%
Exelon Corp.	BBB	-	13.4%	0.49	-	0.00	5.7%	0.51	25.7%	8.7%
IDACORP Inc.	BBB	-	7.9%	0.66	-	0.00	5.7%	0.34	25.7%	6.6%
MGE Energy	AA	-	7.0%	0.80	-	0.00	5.2%	0.20	25.7%	6.4%
NextEra Energy	A	-	11.6%	0.64	-	0.00	5.4%	0.36	25.7%	8.8%
NorthWestern Corp.	BBB	-	9.5%	0.57	-	0.00	5.7%	0.43	25.7%	7.3%
OGE Energy	BBB	-	16.7%	0.63	-	0.00	5.7%	0.37	25.7%	12.1%
Otter Tail Corp.	BBB	-	~~11.2%~~	0.83	-	0.00	5.7%	0.17	25.7%	~~8.7%~~
Pinnacle West Capital	BBB	-	11.8%	0.49	-	0.00	5.7%	0.51	25.7%	8.0%
Public Serv. Enterprise	BBB	-	9.4%	0.64	-	0.00	5.7%	0.36	25.7%	7.5%
Sempra Energy	BBB	BBB	10.9%	0.45	5.7%	0.02	5.7%	0.53	25.7%	7.3%
Southern Co.	BBB	-	12.2%	0.59	-	0.00	5.7%	0.41	25.7%	8.9%
WEC Energy Group	A	A	9.8%	0.62	5.4%	0.00	5.4%	0.38	25.7%	7.6%
Xcel Energy Inc.	A	-	9.9%	0.60	-	0.00	5.4%	0.40	25.7%	7.5%
Simple Electric Sample Average			10.5%	56.7%	5.6%	0.4%	5.6%	42.8%	25.7%	7.7%

Sources and Notes:

[1]: Bloomberg as of December 31, 2023.

[6]: Schedule No. D5.4, [2].

[2]: Preferred ratings were assumed equal to debt ratings. [7]: Workpaper #2 to Schedule No. D5.11, Panel B.

[3]: Schedule No. D5.6; Panel A, [6].

[8]: Schedule No. D5.4, [3].

[4]: Schedule No. D5.4, [1].

[9]: Provided by DTE Electric.

[5]: Workpaper #2 to Schedule No. D5.11, Panel C.

[10]: $(([3] \times [4]) + ([5] \times [6]) + ([7] \times [8]) \times (1 - [9]))$. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. D5.7

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	4th Quarter, 2023 S&P Bond Rating	4th Quarter, 2023 Preferred Equity Rating	DCF Cost of Equity	DCF Common Equity to Market Value Ratio	Cost of Preferred Equity	DCF Preferred Equity to Market Value Ratio	DCF Cost of Debt	DCF Debt to Market Value Ratio	DTE Electric's Representative Income Tax Rate	Overall Weighted After-Tax Cost of Capital
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	BBB	-	9.2%	0.68	-	0.00	5.7%	0.32	25.7%	7.6%
Alliant Energy	A	-	8.5%	0.61	-	0.00	5.4%	0.39	25.7%	6.7%
Amer. Elec. Power	A	-	8.9%	0.53	-	0.00	5.4%	0.47	25.7%	6.6%
Ameren Corp.	BBB	-	8.0%	0.58	-	0.00	5.7%	0.42	25.7%	6.4%
Avista Corp.	BBB	-	10.2%	0.52	-	0.00	5.7%	0.48	25.7%	7.3%
Black Hills	BBB	-	9.1%	0.45	-	0.00	5.7%	0.55	25.7%	6.4%
CMS Energy Corp.	BBB	BBB	8.3%	0.55	5.7%	0.01	5.7%	0.44	25.7%	6.4%
CenterPoint Energy	BBB	-	~~7.1%~~	0.54	-	0.00	5.7%	0.46	25.7%	~~5.8%~~
Duke Energy	BBB	BBB	9.2%	0.45	5.7%	0.01	5.7%	0.53	25.7%	6.5%
Edison Int'l	BBB	BBB	9.0%	0.43	5.7%	0.06	5.7%	0.50	25.7%	6.4%
Entergy Corp.	BBB	BBB	7.9%	0.48	5.7%	0.01	5.7%	0.51	25.7%	6.0%
Eversource Energy	BBB	-	9.6%	0.52	-	0.00	5.7%	0.48	25.7%	7.0%
Exelon Corp.	BBB	-	9.6%	0.49	-	0.00	5.7%	0.51	25.7%	6.9%
IDACORP Inc.	BBB	-	7.6%	0.66	-	0.00	5.7%	0.34	25.7%	6.5%
MGE Energy	AA	-	~~6.6%~~	0.80	-	0.00	5.2%	0.20	25.7%	~~6.0%~~
NextEra Energy	A	-	8.2%	0.64	-	0.00	5.4%	0.36	25.7%	6.7%
NorthWestern Corp.	BBB	-	9.3%	0.57	-	0.00	5.7%	0.43	25.7%	7.2%
OGE Energy	BBB	-	11.6%	0.63	-	0.00	5.7%	0.37	25.7%	8.9%
Otter Tail Corp.	BBB	-	~~4.6%~~	0.83	-	0.00	5.7%	0.17	25.7%	~~4.5%~~
Pinnacle West Capital	BBB	-	10.0%	0.49	-	0.00	5.7%	0.51	25.7%	7.0%
Public Serv. Enterprise	BBB	-	8.3%	0.64	-	0.00	5.7%	0.36	25.7%	6.8%
Sempra Energy	BBB	BBB	8.2%	0.45	5.7%	0.02	5.7%	0.53	25.7%	6.0%
Southern Co.	BBB	-	9.3%	0.59	-	0.00	5.7%	0.41	25.7%	7.2%
WEC Energy Group	A	A	8.4%	0.62	5.4%	0.00	5.4%	0.38	25.7%	6.7%
Xcel Energy Inc.	A	-	8.1%	0.60	-	0.00	5.4%	0.40	25.7%	6.5%
Multi-Stage Electric Sample Average			8.9%	0.55	5.6%	0.00	5.6%	0.44	25.7%	6.8%

Sources and Notes:

[1]: Bloomberg as of December 31, 2023.

[6]: Schedule No. D5.4, [2].

[2]: Preferred ratings were assumed equal to debt ratings. [7]: Workpaper #2 to Schedule No. D5.11, Panel B.

[3]: Schedule No. D5.6, Panel B, [10].

[8]: Schedule No. D5.4, [3].

[4]: Schedule No. D5.4, [1].

[9]: Provided by DTE Electric.

[5]: Workpaper #2 to Schedule No. D5.11, Panel C.

[10]: $([3] \times [4]) + ([5] \times [6]) + ([7] \times [8] \times (1 - [9]))$. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 150 basis points

Schedule No. D5.8
DCF Cost of Equity at DTE Electric's Proposed Capital Structure

Electric Sample

	Overall After -Tax Cost of Capital	DTE Electric's Representative Regulatory % Debt	Representative Cost of BBB Rated Utility Debt	DTE Electric's Representative Income Tax Rate	DTE Electric's Representative Regulatory % Equity	Estimated Return on Equity
	[1]	[2]	[3]	[4]	[5]	[6]
Electric Sample						
Simple DCF Quarterly	7.7%	50.0%	5.7%	25.7%	50.0%	11.22%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	6.8%	50.0%	5.7%	25.7%	50.0%	9.39%

Sources and Notes:

[1]: Schedule No. D5.7; Panels A-B, [10].

[2]: Provided by DTE Electric.

[3]: Based on a BBB rating. Yield from Bloomberg as of December 31, 2023.

[4]: Provided by DTE Electric.

[5]: Provided by DTE Electric.

[6]: $\{[1] - ([2] \times [3] \times (1 - [4]))\} / [5]$.

Schedule No. D5.9 Risk-Free Rates

BCEI Forecast of 10 year U.S. Treasury Yield	[a]	3.80%
Long-run Average of 20 year U.S. Treasury Yield	[b]	4.35%
Long-run Average of 10 year U.S. Treasury Yield	[c]	3.85%
Maturity Premium	[d] = [b] - [c]	0.50%
Base Projection of 20 year U.S. Treasury Yield	[e] = [a] + [d]	4.30%

Sources and Notes:

Blue Chip Economic Indicators, January 2024 - average of 2024 and 2025 forecast.

[b], [c]: Bloomberg as of 12/31/2023, see Workpaper #1 to Schedule No. D5.9.

Schedule No. D5.10

Risk Positioning Cost of Equity of the Electric Sample (Using Value Line Betas)

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 7.17%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE	4.30%	0.95	7.17%	11.1%	11.2%
Alliant Energy	4.30%	0.90	7.17%	10.7%	10.9%
Amer. Elec. Power	4.30%	0.80	7.17%	10.0%	10.3%
Ameren Corp.	4.30%	0.90	7.17%	10.7%	10.9%
Avista Corp.	4.30%	0.95	7.17%	11.1%	11.2%
Black Hills	4.30%	1.00	7.17%	11.5%	11.5%
CMS Energy Corp.	4.30%	0.85	7.17%	10.4%	10.6%
CenterPoint Energy	4.30%	1.15	7.17%	12.5%	12.3%
Duke Energy	4.30%	0.90	7.17%	10.7%	10.9%
Edison Int'l	4.30%	1.00	7.17%	11.5%	11.5%
Entergy Corp.	4.30%	0.95	7.17%	11.1%	11.2%
Eversource Inc.	4.30%	0.95	7.17%	11.1%	11.2%
Exelon Corp.	4.30%	n/a	7.17%	n/a	n/a
IDACORP Inc.	4.30%	0.85	7.17%	10.4%	10.6%
MGE Energy	4.30%	0.75	7.17%	9.7%	10.0%
NextEra Energy	4.30%	1.00	7.17%	11.5%	11.5%
NorthWestern Corp.	4.30%	0.95	7.17%	11.1%	11.2%
OGE Energy	4.30%	1.05	7.17%	11.8%	11.7%
Otter Tail Corp.	4.30%	0.95	7.17%	11.1%	11.2%
Pinnacle West Capital	4.30%	0.95	7.17%	11.1%	11.2%
Public Serv. Enterprise	4.30%	0.95	7.17%	11.1%	11.2%
Sempra Energy	4.30%	1.00	7.17%	11.5%	11.5%
Southern Co.	4.30%	0.95	7.17%	11.1%	11.2%
WEC Energy Group	4.30%	0.85	7.17%	10.4%	10.6%
Xcel Energy Inc.	4.30%	0.85	7.17%	10.4%	10.6%

Sources and Notes:

[1], [3]: Villadsen Direct Testimony.

[2]: From Valueline Investment Analyzer as of December 31, 2023.

[4]: $[1] + ([2] \times [3])$.

[5]: $([1] + 1.5\%) + [2] \times ([3] - 1.5\%)$.

Schedule No. D5.10

Risk Positioning Cost of Equity of the Electric Sample (Using Value Line Betas)

Panel B: Scenario 2 - Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 6.37%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1.5%) Cost of Equity [5]
ALLETE	4.30%	0.95	6.37%	10.4%	10.4%
Alliant Energy	4.30%	0.90	6.37%	10.0%	10.2%
Amer. Elec. Power	4.30%	0.80	6.37%	9.4%	9.7%
Ameren Corp.	4.30%	0.90	6.37%	10.0%	10.2%
Avista Corp.	4.30%	0.95	6.37%	10.4%	10.4%
Black Hills	4.30%	1.00	6.37%	10.7%	10.7%
CMS Energy Corp.	4.30%	0.85	6.37%	9.7%	9.9%
CenterPoint Energy	4.30%	1.15	6.37%	11.6%	11.4%
Duke Energy	4.30%	0.90	6.37%	10.0%	10.2%
Edison Int'l	4.30%	1.00	6.37%	10.7%	10.7%
Entergy Corp.	4.30%	0.95	6.37%	10.4%	10.4%
Evergy Inc.	4.30%	0.95	6.37%	10.4%	10.4%
Exelon Corp.	4.30%	n/a	6.37%	n/a	n/a
IDACORP Inc.	4.30%	0.85	6.37%	9.7%	9.9%
MGE Energy	4.30%	0.75	6.37%	9.1%	9.5%
NextEra Energy	4.30%	1.00	6.37%	10.7%	10.7%
NorthWestern Corp.	4.30%	0.95	6.37%	10.4%	10.4%
OGE Energy	4.30%	1.05	6.37%	11.0%	10.9%
Otter Tail Corp.	4.30%	0.95	6.37%	10.4%	10.4%
Pinnacle West Capital	4.30%	0.95	6.37%	10.4%	10.4%
Public Serv. Enterprise	4.30%	0.95	6.37%	10.4%	10.4%
Sempra Energy	4.30%	1.00	6.37%	10.7%	10.7%
Southern Co.	4.30%	0.95	6.37%	10.4%	10.4%
WEC Energy Group	4.30%	0.85	6.37%	9.7%	9.9%
Xcel Energy Inc.	4.30%	0.85	6.37%	9.7%	9.9%

Sources and Notes:

[1], [3]: Villadsen Direct Testimony.

[2]: From Valueline Investment Analyzer as of December 31, 2023.

[4]: $[1] + ([2] \times [3])$.

[5]: $([1] + 1.5\%) + [2] \times ([3] - 1.5\%)$.

Schedule No. D5.11

Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample (Using Value Line Betas)

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 7.17%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted- Average Cost of Debt	5-Year Average Debt to Market Value Ratio	DTE Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	11.1%	11.2%	0.32	-	0.00	5.7%	0.18	25.7%	4.3%	4.3%
Alliant Energy	10.7%	10.9%	0.62	5.4%	0.01	5.4%	0.38	25.7%	8.2%	8.3%
Amer. Elec. Power	10.0%	10.3%	0.54	-	0.00	5.4%	0.46	25.7%	7.3%	7.4%
Ameren Corp.	10.7%	10.9%	0.61	-	0.00	5.7%	0.39	25.7%	8.2%	8.3%
Avista Corp.	11.1%	11.2%	0.54	-	0.00	5.7%	0.46	25.7%	7.9%	8.0%
Black Hills	11.5%	11.5%	0.50	-	0.00	5.7%	0.50	25.7%	7.9%	7.9%
CMS Energy Corp.	10.4%	10.6%	0.55	5.7%	0.00	5.7%	0.44	25.7%	7.6%	7.8%
CenterPoint Energy	12.5%	12.3%	0.49	5.7%	0.04	5.7%	0.47	25.7%	8.3%	8.2%
Duke Energy	10.7%	10.9%	0.50	5.6%	0.01	5.6%	0.49	25.7%	7.4%	7.5%
Edison Int'l	11.5%	11.5%	0.46	5.7%	0.05	5.7%	0.49	25.7%	7.6%	7.6%
Entergy Corp.	11.1%	11.2%	0.47	5.7%	0.01	5.7%	0.52	25.7%	7.5%	7.5%
Eversource Inc.	11.1%	11.2%	0.56	-	0.00	5.4%	0.44	25.7%	8.0%	8.0%
Exelon Corp.	~~n/a~~	~~n/a~~	0.46	-	0.00	5.7%	0.54	25.7%	~~n/a~~	~~n/a~~
IDACORP Inc.	10.4%	10.6%	0.69	-	0.00	5.7%	0.31	25.7%	8.5%	8.6%
MGE Energy	9.7%	10.0%	0.80	-	0.00	5.2%	0.20	25.7%	8.5%	8.8%
NextEra Energy	11.5%	11.5%	0.72	-	0.00	5.4%	0.28	25.7%	9.3%	9.3%
NorthWestern Corp.	11.1%	11.2%	0.56	-	0.00	5.7%	0.44	25.7%	8.1%	8.1%
OGE Energy	11.8%	11.7%	0.63	-	0.00	5.7%	0.37	25.7%	9.0%	9.0%
Otter Tail Corp.	11.1%	11.2%	0.74	-	0.00	5.7%	0.26	25.7%	9.3%	9.3%
Pinnacle West Capital	11.1%	11.2%	0.54	-	0.00	5.6%	0.46	25.7%	7.9%	7.9%
Public Serv. Enterprise	11.1%	11.2%	0.62	-	0.00	5.7%	0.38	25.7%	8.5%	8.6%
Sempra Energy	11.5%	11.5%	0.57	5.7%	0.03	5.7%	0.41	25.7%	8.4%	8.4%
Southern Co.	11.1%	11.2%	0.55	5.5%	0.00	5.6%	0.44	25.7%	8.0%	8.0%
WEC Energy Group	10.4%	10.6%	0.65	5.4%	0.00	5.4%	0.35	25.7%	8.2%	8.3%
Xcel Energy Inc.	10.4%	10.6%	0.59	-	0.00	5.4%	0.41	25.7%	7.8%	7.9%
Electric Sample Average	11.0%	11.1%	57.5%	5.6%	0.6%	5.6%	39.7%	25.7%	8.0%	8.0%

Sources and Notes:

- [1]: Schedule No. D5.10; Panel A, [4].
[2]: Schedule No. D5.10; Panel A, [5].
[3]: Schedule No. D5.4, [4].
[4]: Workpaper #2 to Schedule No. D5.11, Panel C.
[5]: Schedule No. D5.4, [5].
[6]: Workpaper #2 to Schedule No. D5.11, Panel B.
[7]: Schedule No. D5.4, [6].
[8]: Provided by DTE Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. D5.11

Overall After-Tax Risk Positioning Cost of Capital of the Electric Sample (Using Value Line Betas)

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 6.37%

Company	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity	5-Year Average Common Equity to Market Value Ratio	Weighted - Average Cost of Preferred Equity	5-Year Average Preferred Equity to Market Value Ratio	Weighted- Average Cost of Debt	5-Year Average Debt to Market Value Ratio	DTE Electric's Representative Income Tax Rate	Overall After-Tax Cost of Capital (CAPM)	Overall After-Tax Cost of Capital (ECAPM 1.5%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ALLETE	10.4%	10.4%	0.32	-	0.00	5.7%	0.18	25.7%	4.1%	4.1%
Alliant Energy	10.0%	10.2%	0.62	5.4%	0.01	5.4%	0.38	25.7%	7.7%	7.8%
Amer. Elec. Power	9.4%	9.7%	0.54	-	0.00	5.4%	0.46	25.7%	6.9%	7.1%
Ameren Corp.	10.0%	10.2%	0.61	-	0.00	5.7%	0.39	25.7%	7.8%	7.9%
Avista Corp.	10.4%	10.4%	0.54	-	0.00	5.7%	0.46	25.7%	7.5%	7.6%
Black Hills	10.7%	10.7%	0.50	-	0.00	5.7%	0.50	25.7%	7.5%	7.5%
CMS Energy Corp.	9.7%	9.9%	0.55	5.7%	0.00	5.7%	0.44	25.7%	7.3%	7.4%
CenterPoint Energy	11.6%	11.4%	0.49	5.7%	0.04	5.7%	0.47	25.7%	7.9%	7.8%
Duke Energy	10.0%	10.2%	0.50	5.6%	0.01	5.6%	0.49	25.7%	7.1%	7.1%
Edison Int'l	10.7%	10.7%	0.46	5.7%	0.05	5.7%	0.49	25.7%	7.2%	7.2%
Entergy Corp.	10.4%	10.4%	0.47	5.7%	0.01	5.7%	0.52	25.7%	7.1%	7.1%
Eversource Inc.	10.4%	10.4%	0.56	-	0.00	5.4%	0.44	25.7%	7.6%	7.6%
Exelon Corp.	~~n/a~~	~~n/a~~	0.46	-	0.00	5.7%	0.54	25.7%	~~n/a~~	~~n/a~~
IDACORP Inc.	9.7%	9.9%	0.69	-	0.00	5.7%	0.31	25.7%	8.0%	8.2%
MGE Energy	9.1%	9.5%	0.80	-	0.00	5.2%	0.20	25.7%	8.0%	8.3%
NextEra Energy	10.7%	10.7%	0.72	-	0.00	5.4%	0.28	25.7%	8.8%	8.8%
NorthWestern Corp.	10.4%	10.4%	0.56	-	0.00	5.7%	0.44	25.7%	7.6%	7.7%
OGE Energy	11.0%	10.9%	0.63	-	0.00	5.7%	0.37	25.7%	8.5%	8.4%
Otter Tail Corp.	10.4%	10.4%	0.74	-	0.00	5.7%	0.26	25.7%	8.7%	8.8%
Pinnacle West Capital	10.4%	10.4%	0.54	-	0.00	5.6%	0.46	25.7%	7.5%	7.5%
Public Serv. Enterprise	10.4%	10.4%	0.62	-	0.00	5.7%	0.38	25.7%	8.0%	8.1%
Sempra Energy	10.7%	10.7%	0.57	5.7%	0.03	5.7%	0.41	25.7%	7.9%	7.9%
Southern Co.	10.4%	10.4%	0.55	5.5%	0.00	5.6%	0.44	25.7%	7.6%	7.6%
WEC Energy Group	9.7%	9.9%	0.65	5.4%	0.00	5.4%	0.35	25.7%	7.7%	7.9%
Xcel Energy Inc.	9.7%	9.9%	0.59	-	0.00	5.4%	0.41	25.7%	7.4%	7.5%
Electric Sample Average	10.2%	10.3%	0.58	5.6%	0.01	5.6%	0.40	25.7%	7.6%	7.6%

Sources and Notes:

- [1]: Schedule No. D5.10; Panel B, [4].
[2]: Schedule No. D5.10; Panel B, [5].
[3]: Schedule No. D5.4, [4].
[4]: Workpaper #2 to Schedule No. D5.11, Panel C.
[5]: Schedule No. D5.4, [5].
[6]: Workpaper #2 to Schedule No. D5.11, Panel B.
[7]: Schedule No. D5.4, [6].
[8]: Provided by DTE Electric.
[9] = [1] x [3] + [4] x [5] + [6] x [7] x (1 - [8])
[10] = [2] x [3] + [4] x [5] + [6] x [7] x (1 - [8])

Schedule No. D5.12
Risk Positioning Cost of Equity at DTE Electric's Proposed Capital Structure
Electric Sample
Using Value Line Betas

	Overall After-Tax Cost of Capital (Scenario 1)	Overall After-Tax Cost of Capital (Scenario 2)	DTE Electric's Representative Regulatory % Debt	Representative Cost of BBB-Rated Utility Debt	DTE Electric's Representative Income Tax Rate	DTE Electric's Representative Regulatory % Equity	Estimated Return on Equity (Scenario 1)	Estimated Return on Equity (Scenario 2)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Electric Sample								
CAPM using Value Line Betas	8.0%	7.6%	50.0%	5.7%	25.7%	50.0%	11.7%	10.9%
ECAPM (1.50%) using Value Line Betas	8.0%	7.6%	50.0%	5.7%	25.7%	50.0%	11.9%	11.0%

Sources and Notes:

[1]: Schedule No. D5.11; Panel A, [9] - [10].

[2]: Schedule No. D5.11; Panel B, [9] - [10].

[3]: Provided by DTE Electric.

[4]: Based on a BBB rating. Yield from Bloomberg as of December 31, 2023.

[5]: Provided by DTE Electric.

[6]: Provided by DTE Electric.

[7]: $\{[1] - ([3] \times [4] \times (1 - [5]))\} / [6]$

[8]: $\{[2] - ([3] \times [4] \times (1 - [5]))\} / [6]$

Scenario 1: Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 7.17%.

Scenario 2: Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 6.37%.

Schedule No. D5.13

Hamada Adjustment to Obtain Unlevered Asset Beta

Company	Value Line Betas	Debt Beta	5-Year Average Common Equity to Market Value Ratio	5-Year Average Preferred Equity to Market Value Ratio	5-Year Average Debt to Market Value Ratio	DTE Electric's Representative Income Tax Rate	Asset Beta: Without Taxes	Asset Beta: With Taxes
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
ALLETE	0.95	0.10	0.32	0.00	0.18	25.7%	0.32	0.70
Alliant Energy	0.90	0.05	0.62	0.01	0.38	25.7%	0.57	0.63
Amer. Elec. Power	0.80	0.05	0.54	0.00	0.46	25.7%	0.46	0.51
Ameren Corp.	0.90	0.10	0.61	0.00	0.39	25.7%	0.59	0.64
Avista Corp.	0.95	0.10	0.54	0.00	0.46	25.7%	0.56	0.62
Black Hills	1.00	0.10	0.50	0.00	0.50	25.7%	0.55	0.62
CMS Energy Corp.	0.85	0.10	0.55	0.00	0.44	25.7%	0.51	0.57
CenterPoint Energy	1.15	0.10	0.49	0.04	0.47	25.7%	0.61	0.68
Duke Energy	0.90	0.08	0.50	0.01	0.49	25.7%	0.49	0.55
Edison Int'l	1.00	0.10	0.46	0.05	0.49	25.7%	0.51	0.57
Entergy Corp.	0.95	0.10	0.47	0.01	0.52	25.7%	0.50	0.56
Eversource Inc.	0.95	0.06	0.56	0.00	0.44	25.7%	0.56	0.62
Exelon Corp.	n/a	0.10	0.46	0.00	0.54	25.7%	n/a	n/a
IDACORP Inc.	0.85	0.10	0.69	0.00	0.31	25.7%	0.62	0.66
MGE Energy	0.75	0.05	0.80	0.00	0.20	25.7%	0.61	0.64
NextEra Energy	1.00	0.05	0.72	0.00	0.28	25.7%	0.73	0.78
NorthWestern Corp.	0.95	0.10	0.56	0.00	0.44	25.7%	0.57	0.64
OGE Energy	1.05	0.10	0.63	0.00	0.37	25.7%	0.70	0.76
Otter Tail Corp.	0.95	0.10	0.74	0.00	0.26	25.7%	0.73	0.77
Pinnacle West Capital	0.95	0.08	0.54	0.00	0.46	25.7%	0.55	0.61
Public Serv. Enterprise	0.95	0.10	0.62	0.00	0.38	25.7%	0.63	0.69
Sempra Energy	1.00	0.10	0.57	0.03	0.41	25.7%	0.61	0.67
Southern Co.	0.95	0.08	0.55	0.00	0.44	25.7%	0.56	0.62
WEC Energy Group	0.85	0.05	0.65	0.00	0.35	25.7%	0.57	0.62
Xcel Energy Inc.	0.85	0.05	0.59	0.00	0.41	25.7%	0.52	0.58
Electric Sample Average	0.93	0.08	0.57	0.01	0.40	0.26	0.57	0.64

Sources and Notes:

[1]: Workpaper # 1 to Schedule No. D5.10, [1].

[2]: Workpaper #1 to Schedule No. D5.13, [7].

[3]: Schedule No. D5.4, [4].

[4]: Schedule No. D5.4, [5].

[5]: Schedule No. D5.4, [6].

[6]: DTE Electric's Representative Tax Rate.

[7]: $[1] \times [3] + [2] \times ([4] + [5])$.

[8]: $\{[1] \times [3] + [2] \times ([4] + [5] \times (1 - [6]))\} / \{[3] + [4] + [5] \times (1 - [6])\}$.

Schedule No. D5.14

Electric Sample Average Asset Beta Relevered at DTE Electric's Proposed Capital Structure

	Asset Beta	Assumed Debt Beta	DTE Electric's Representative Regulatory % Debt	DTE Electric's Representative Income Tax Rate	DTE Electric's Representative Regulatory % Equity	Estimated Equity Beta
	[1]	[2]	[3]	[4]	[5]	[6]
Electric Sample						
Asset Beta Without Taxes	0.57	0.10	50.0%	25.7%	50.0%	1.04
Asset Beta With Taxes	0.64	0.10	50.0%	25.7%	50.0%	1.04

Sources and Notes:

[1]: Schedule No. D5.13, [7] - [8].

[2]: Villadsen Direct Testimony

[3]: Provided by DTE Electric.

[4]: DTE Electric's Representative Tax Rate.

[5]: Provided by DTE Electric.

[6]: $[1] + [3]/[5]*([1] - [2])$ without taxes, $[1] + [3]*(1 - [4])/[5]*([1] - [2])$ with taxes.

Schedule No. D5.15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 7.17%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Electric Sample					
Asset Beta Without Taxes	4.30%	1.04	7.17%	11.7%	11.7%
Asset Beta With Taxes	4.30%	1.04	7.17%	11.7%	11.7%

Sources and Notes:

- [1]: Villadsen Direct Testimony.
[2]: Schedule No. D5.14, [6].
[3]: Villadsen Direct Testimony.
[4]: $[1] + ([2] \times [3])$.
[5]: $([1] + 1.5\%) + [2] \times ([3] - 1.5\%)$.

Schedule No. D5.15

Risk-Positioning Cost of Equity using Hamada-Adjusted Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 4.30%, Long-Term Market Risk Premium of 6.37%

Company	Long-Term Risk-Free Rate	Hamada Adjusted Equity Betas	Long-Term Market Risk Premium	CAPM Cost of Equity	ECAPM (1.5%) Cost of Equity
	[1]	[2]	[3]	[4]	[5]
Electric Sample					
Asset Beta Without Taxes	4.30%	1.04	6.37%	10.9%	10.8%
Asset Beta With Taxes	4.30%	1.04	6.37%	10.9%	10.9%

Sources and Notes:

- [1]: Villadsen Direct Testimony.
[2]: Schedule No. D5.14, [6].
[3]: Villadsen Direct Testimony.
[4]: $[1] + ([2] \times [3])$.
[5]: $([1] + 1.5\%) + [2] \times ([3] - 1.5\%)$.

Schedule No. D5.16
Risk Premiums Determined by Relationship Between
Authorized ROEs^[1] and Long-term Treasury Bond Rates
During the Period 1990 - 2023
Electric Utilities

$$\text{Risk Premium} = A_0 + (A_1 \times \text{Treasury Bond Rate})$$

R Squared	0.856
Estimate of Intercept (A_0)	8.64%
Estimate of Slope (A_1)	-0.563

Predicted Risk Premium	+	Exp. Treasury Bond Rate	=	Est. Cost of Equity for Vertically Integrated Electric Utilities
6.22%		4.30%		10.5%

Sources and Notes:

[1]: Authorized ROE Data from S&P Market Intelligence as of 12/31/2023.

[2]: January 2024 Blue Chip Economic Indicators for 2024-2025 yield projections 10 year T-bill yield + maturity premium between 10 year and 20 year U.S. Government

See Regression Results for derivation of regression coefficients A_0 and A_1

Schedule D5.17

Panel A: Market Risk Premium Summary (20 Year UST)

		IBES	Value Line
Dividend Yield	[a]	1.35%	1.55%
Growth Rate	[b]	10.94%	10.76%
Estimated Cost of Equity	[c] = [a] + [b]	12.28%	12.31%
Risk Free Rate (20-Year)	[d]	4.59%	4.59%
Market Risk Premium	[e] = [c] - [d]	7.69%	7.71%

Note: Based on 20-Year U.S. Government Bond Yield, consistent with the risk-free rate used in Villadsen Direct.

Schedule D5.17

Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
3M Company	57,259	5.8%	2%	3	2%	6%	5%	5%	6%
Abbott Labs.	186,453	2.1%	-2%	2	n/a	n/a	5%	5%	2%
AbbVie Inc.	267,807	4.1%	-4%	4	n/a	n/a	2%	2%	4%
Accenture Plc	212,864	1.5%	8%	2	8%	2%	8%	8%	2%
Adobe Inc.	271,803	0.0%	14%	5	14%	0%	12%	12%	0%
Advanced Micro Dev.	218,784	0.0%	13%	3	13%	0%	12%	12%	0%
AES Corp.	12,301	3.6%	8%	3	8%	4%	n/a	n/a	n/a
Aflac Inc.	47,374	2.6%	n/a	NULL	n/a	n/a	8%	8%	3%
Agilent Technologies	40,487	0.7%	8%	3	8%	1%	12%	12%	1%
Air Products & Chem.	59,583	2.6%	10%	4	10%	3%	11%	11%	3%
Airbnb Inc.	90,144	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Akamai Technologies	18,018	0.0%	11%	3	11%	0%	5%	5%	0%
Albemarle Corp.	16,726	1.1%	n/a	NULL	n/a	n/a	-5%	n/a	n/a
Alexandria Real Estate	19,989	4.0%	n/a	NULL	n/a	n/a	10%	10%	4%
Align Techn.	20,072	0.0%	n/a	NULL	n/a	n/a	16%	16%	0%
Allegion plc	10,582	1.7%	11%	2	11%	2%	10%	10%	2%
Alliant Energy	12,823	3.6%	7%	2	7%	4%	7%	7%	4%
Allstate Corp.	35,532	2.6%	n/a	NULL	n/a	n/a	11%	11%	3%
Alphabet Inc.	1,794,491	0.0%	19%	5	19%	0%	13%	13%	0%
Alphabet Inc. 'A'	1,734,922	0.0%	19%	5	19%	0%	17%	17%	0%
Altria Group	71,326	9.7%	2%	3	2%	10%	6%	6%	10%
Amazon.com	1,571,400	0.0%	n/a	NULL	n/a	n/a	20%	20%	0%
Amcor plc	13,891	5.2%	5%	2	5%	5%	8%	8%	5%
Amer. Airlines	9,136	0.0%	83%	3	n/a	3%	n/a	n/a	n/a
Amer. Elec. Power	42,219	4.4%	4%	1	4%	4%	7%	7%	4%
Amer. Express	131,694	1.3%	14%	3	14%	1%	9%	9%	1%
Amer. Int'l Group	46,939	2.2%	n/a	NULL	n/a	n/a	9%	9%	2%
Amer. Tower 'A'	98,411	3.2%	6%	4	6%	3%	5%	5%	3%
Amer. Water Works	25,467	2.2%	8%	2	8%	2%	3%	3%	2%
Ameren Corp.	18,939	3.5%	5%	1	5%	4%	6%	6%	4%
Ameriprise Fin'l	37,793	1.5%	n/a	NULL	n/a	n/a	13%	13%	1%
AMETEK Inc.	37,348	0.6%	n/a	NULL	n/a	n/a	13%	13%	1%
Amgen	147,249	3.3%	5%	4	5%	3%	6%	6%	3%
Amphenol Corp.	58,397	0.9%	n/a	NULL	n/a	n/a	13%	13%	1%
Analog Devices	95,771	1.8%	n/a	NULL	n/a	n/a	12%	12%	2%
ANSYS Inc.	25,768	0.0%	10%	2	10%	0%	9%	9%	0%
Aon plc	59,059	0.8%	9%	1	9%	1%	9%	9%	1%
APA Corp.	10,897	3.2%	0%	2	0%	3%	20%	20%	3%
Apple Inc.	3,048,674	0.5%	6%	3	6%	0%	11%	11%	0%
Applied Materials	131,269	0.9%	15%	3	15%	1%	4%	4%	1%
Aptiv PLC	24,504	0.0%	29%	4	n/a	n/a	33%	n/a	n/a
Arch Capital Group	27,464	0.0%	20%	2	20%	0%	26%	n/a	n/a
Archer Daniels Mid'l d	37,814	2.6%	-5%	2	n/a	n/a	8%	8%	3%
Arista Networks	72,506	0.0%	19%	4	19%	0%	17%	17%	0%
Assurant Inc.	8,653	1.8%	15%	1	15%	2%	11%	11%	2%
AT&T Inc.	117,253	6.8%	0%	2	0%	7%	2%	2%	7%
Atmos Energy	16,669	2.9%	8%	1	8%	3%	8%	8%	3%
Autodesk Inc.	50,656	0.0%	12%	3	12%	0%	10%	10%	0%
Automatic Data Proc.	95,609	2.4%	11%	2	11%	2%	11%	11%	2%
AutoZone Inc.	45,175	0.0%	9%	2	9%	0%	13%	13%	0%
AvalonBay Communities	26,053	3.8%	n/a	NULL	n/a	n/a	6%	6%	4%
Avery Dennison	16,200	1.7%	n/a	NULL	n/a	n/a	10%	10%	2%
Axon Enterprise	18,941	0.0%	38%	2	n/a	n/a	24%	n/a	n/a
Baker Hughes	34,234	2.4%	n/a	LTGNumOfEst	n/a	n/a	n/a	n/a	n/a
Ball Corp.	17,559	1.5%	n/a	NULL	n/a	n/a	11%	11%	2%
Bank of America	261,312	3.0%	n/a	NULL	n/a	n/a	5%	5%	3%
Bank of NY Mellon	39,146	3.3%	n/a	NULL	n/a	n/a	7%	7%	3%
Bath & Body Works	9,559	1.9%	4%	3	4%	2%	17%	17%	2%
Baxter Int'l Inc.	19,582	3.0%	5%	3	5%	3%	6%	6%	3%
Becton Dickinson	69,574	1.6%	8%	2	8%	2%	5%	5%	2%
Berkley (W.R.)	17,885	0.6%	9%	2	9%	1%	15%	15%	1%
Berkshire Hathaway 'B'	n/a	0.0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Best Buy Co.	16,354	4.9%	-1%	3	n/a	n/a	1%	1%	5%
Bio-Rad Labs. 'A'	8,986	0.0%	n/a	NULL	n/a	n/a	11%	11%	0%
Bio-Techne Corp.	12,013	0.4%	10%	2	10%	0%	11%	11%	0%
Biogen	35,958	0.0%	0%	3	0%	0%	-7%	n/a	n/a
BlackRock Inc.	117,550	2.7%	9%	2	9%	3%	8%	8%	3%
Blackstone Inc.	89,566	2.5%	6%	3	6%	3%	15%	15%	3%
Boeing	157,350	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Booking Holdings	122,075	0.0%	27%	3	n/a	n/a	28%	n/a	n/a
BorgWarner	8,206	1.3%	11%	4	11%	1%	7%	7%	1%
Boston Properties	11,072	5.5%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Boston Scientific	80,539	0.0%	12%	5	12%	0%	14%	14%	0%
Bristol-Myers Squibb	103,653	4.7%	0%	5	n/a	n/a	29%	n/a	n/a
Broadcom Inc.	458,587	1.9%	n/a	NULL	n/a	n/a	24%	n/a	n/a
Broadridge Fin'l	23,190	1.6%	n/a	NULL	n/a	n/a	10%	10%	2%
Brown & Brown	19,807	0.8%	13%	1	13%	1%	7%	7%	1%
Brown-Forman 'B'	27,282	1.5%	11%	2	11%	2%	17%	17%	2%
Builders FirstSource	19,922	0.0%	-12%	2	n/a	n/a	22%	n/a	n/a
Bunge Global SA	15,301	2.7%	n/a	NULL	n/a	n/a	2%	2%	3%
C.H. Robinson	9,928	2.9%	-16%	3	n/a	n/a	6%	6%	3%
Cadence Design Sys.	73,672	0.0%	18%	2	18%	0%	14%	14%	0%
Caesars Entertainment	10,014	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Camden Property Trust	10,313	4.4%	n/a	NULL	n/a	n/a	-3%	n/a	n/a

Schedule D5.17

Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
Campbell Soup	12,695	3.7%	5%	3	5%	4%	5%	5%	4%
Capital One Fin'l	48,664	1.9%	n/a	NULL	n/a	n/a	4%	4%	2%
Cardinal Health	24,483	2.0%	17%	2	17%	2%	8%	8%	2%
CarMax Inc.	11,848	0.0%	n/a	NULL	n/a	n/a	5%	5%	0%
Carnival Corp.	22,841	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Carrier Global	46,984	1.4%	10%	4	10%	1%	13%	13%	1%
Catalent Inc.	7,760	0.0%	24%	4	n/a	n/a	9%	9%	0%
Caterpillar Inc.	147,487	1.8%	13%	4	13%	2%	15%	15%	2%
Cboe Global Markets	18,377	1.3%	8%	3	8%	1%	13%	13%	1%
CBRE Group	27,348	0.0%	n/a	NULL	n/a	n/a	3%	3%	0%
CDW Corp.	29,803	1.1%	8%	2	8%	1%	7%	7%	1%
Celanese Corp.	16,457	1.9%	-4%	2	n/a	n/a	5%	5%	2%
Cencora	40,379	1.0%	9%	2	9%	1%	8%	8%	1%
Centene Corp.	38,603	0.0%	12%	3	12%	0%	10%	10%	0%
CenterPoint Energy	17,859	2.8%	n/a	NULL	n/a	n/a	9%	9%	3%
Ceridian HCM Holding	10,385	0.0%	43%	2	n/a	n/a	n/a	n/a	n/a
CF Industries	15,007	2.3%	-26%	2	n/a	n/a	6%	6%	2%
Charles River	11,881	0.0%	4%	2	4%	0%	8%	8%	0%
Charter Communic.	56,390	0.0%	11%	3	11%	0%	13%	13%	0%
Chevron Corp.	283,634	4.3%	-5%	2	n/a	n/a	17%	17%	4%
Chipotle Mex. Grill	63,597	0.0%	26%	3	n/a	n/a	22%	n/a	n/a
Chubb Ltd.	89,271	1.6%	n/a	NULL	n/a	n/a	18%	18%	2%
Church & Dwight	22,521	1.2%	7%	4	7%	1%	6%	6%	1%
Cigna Group	87,566	1.7%	11%	4	11%	2%	12%	12%	2%
Cincinnati Financial	15,844	3.2%	n/a	NULL	n/a	n/a	13%	13%	3%
Cintas Corp.	56,433	1.0%	12%	3	12%	1%	14%	14%	1%
Cisco Systems	201,640	3.1%	6%	3	6%	3%	6%	6%	3%
Citigroup Inc.	95,828	4.2%	n/a	NULL	n/a	n/a	3%	3%	4%
Citizens Fin'l Group	15,096	5.2%	n/a	NULL	n/a	n/a	5%	5%	5%
Clorox Co.	17,435	3.4%	7%	3	7%	3%	10%	10%	3%
CME Group	75,808	2.1%	9%	3	9%	2%	8%	8%	2%
CMS Energy Corp.	16,662	3.4%	8%	2	8%	3%	6%	6%	3%
Coca-Cola	249,106	3.3%	6%	3	6%	3%	8%	8%	3%
Cognizant Technology	37,089	1.6%	4%	2	4%	2%	7%	7%	2%
Colgate-Palmolive	63,688	2.5%	8%	3	8%	3%	9%	9%	3%
Comcast Corp.	179,386	2.6%	9%	4	9%	3%	9%	9%	3%
Comerica Inc.	7,096	5.3%	n/a	NULL	n/a	n/a	3%	3%	5%
Conagra Brands	13,555	4.9%	n/a	NULL	n/a	n/a	4%	4%	5%
ConocoPhillips	138,559	2.1%	n/a	NULL	n/a	n/a	9%	9%	2%
Consol. Edison	30,736	3.7%	6%	2	6%	4%	6%	6%	4%
Constellation Brands	43,173	1.5%	12%	4	12%	2%	7%	7%	2%
Constellation Energy	37,326	1.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Cooper Cos.	17,837	0.0%	10%	2	10%	0%	10%	10%	0%
Copart Inc.	45,866	0.0%	n/a	NULL	n/a	n/a	10%	10%	0%
Corning Inc.	24,395	3.8%	6%	3	6%	4%	14%	14%	4%
Corteva Inc.	32,840	1.4%	10%	3	10%	1%	12%	12%	1%
CoStar Group	35,298	0.0%	20%	1	20%	0%	14%	14%	0%
Costco Wholesale	292,686	0.6%	9%	3	9%	1%	11%	11%	1%
Coterra Energy	19,383	3.2%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Crown Castle Int'l	49,654	5.5%	-10%	2	n/a	n/a	7%	7%	5%
CSX Corp.	67,900	1.4%	7%	3	7%	1%	8%	8%	1%
Cummins Inc.	34,094	2.8%	11%	3	11%	3%	9%	9%	3%
CVS Health	99,408	3.4%	2%	2	2%	3%	6%	6%	3%
Danaher Corp.	167,590	0.5%	-1%	4	n/a	n/a	11%	11%	0%
Darden Restaurants	19,570	3.2%	10%	4	10%	3%	15%	15%	3%
DaVita Inc.	9,488	0.0%	18%	2	18%	0%	8%	8%	0%
Deere & Co.	111,531	1.5%	-5%	3	n/a	n/a	13%	13%	2%
Delta Air Lines	25,957	1.0%	33%	3	n/a	n/a	n/a	n/a	n/a
Dentsply Sirona	7,205	1.7%	8%	2	8%	2%	10%	10%	2%
Devon Energy	28,999	1.8%	n/a	NULL	n/a	n/a	11%	11%	2%
DexCom Inc.	45,070	0.0%	34%	2	n/a	n/a	27%	n/a	n/a
Diamondback Energy	27,865	2.2%	n/a	NULL	n/a	n/a	34%	n/a	n/a
Digital Realty Trust	38,647	3.9%	-8%	2	n/a	n/a	-3%	n/a	n/a
Discover Fin'l Svcs.	26,911	2.6%	n/a	NULL	n/a	n/a	2%	2%	3%
Disney (Walt)	162,552	0.7%	17%	6	17%	1%	65%	n/a	n/a
Dollar General	28,295	1.8%	-6%	4	n/a	n/a	2%	2%	2%
Dollar Tree Inc.	29,282	0.0%	2%	3	2%	0%	9%	9%	0%
Dominion Energy	39,490	5.7%	-5%	3	n/a	n/a	1%	1%	6%
Domino's Pizza	14,065	1.3%	13%	4	13%	1%	12%	12%	1%
Dover Corp.	21,121	1.4%	9%	4	9%	1%	7%	7%	1%
Dow Inc.	38,282	5.5%	-11%	3	n/a	n/a	3%	3%	6%
DTE Energy	22,552	3.7%	5%	2	5%	4%	7%	7%	4%
Duke Energy	73,769	4.3%	7%	2	7%	4%	5%	5%	4%
DuPont de Nemours	31,507	2.1%	10%	3	10%	2%	10%	10%	2%
Eastman Chemical	10,429	3.7%	5%	3	5%	4%	6%	6%	4%
Eaton Corp. plc	93,416	1.5%	12%	4	12%	1%	13%	13%	1%
eBay Inc.	22,350	2.5%	7%	6	7%	3%	9%	9%	3%
Ecolab Inc.	55,560	1.2%	15%	7	15%	1%	10%	10%	1%
Edison Int'l	26,378	4.5%	5%	4	5%	5%	5%	5%	5%
Edwards Lifesciences	44,954	0.0%	8%	4	8%	0%	11%	11%	0%
Electronic Arts	36,879	0.6%	10%	1	10%	1%	18%	18%	1%
Elevance Health	107,876	1.3%	12%	3	12%	1%	12%	12%	1%
Emerson Electric	54,146	2.2%	11%	4	11%	2%	7%	7%	2%
Enphase Energy	17,474	0.0%	11%	3	11%	0%	21%	n/a	n/a

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Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
Entergy Corp.	21,069	4.5%	n/a	NULL	n/a	n/a	3%	3%	5%
EOG Resources	70,800	3.0%	n/a	NULL	n/a	n/a	15%	15%	3%
EPAM Systems	16,766	0.0%	5%	2	5%	0%	6%	6%	0%
EQT Corp.	15,630	1.7%	27%	2	n/a	n/a	n/a	n/a	n/a
Equifax Inc.	29,295	0.7%	12%	4	12%	1%	3%	3%	1%
Equinix Inc.	74,584	2.1%	24%	3	n/a	n/a	13%	13%	2%
Equity Residential	22,802	4.4%	n/a	NULL	n/a	n/a	-5%	n/a	n/a
Essex Property Trust	14,966	3.9%	n/a	NULL	n/a	n/a	2%	2%	4%
Etsy Inc.	10,003	0.0%	16%	3	16%	0%	6%	6%	0%
Everest Group	15,485	2.0%	37%	1	n/a	n/a	10%	10%	2%
Evergy Inc.	11,727	5.0%	3%	1	3%	5%	7%	7%	5%
Eversource Energy	21,142	4.7%	n/a	NULL	n/a	n/a	6%	6%	5%
Exelon Corp.	34,636	4.1%	10%	3	10%	4%	2%	2%	4%
Expedia Group	20,763	0.0%	25%	3	n/a	n/a	n/a	n/a	n/a
Expeditors Int'l	18,236	1.0%	-17%	1	n/a	n/a	-2%	n/a	n/a
Extra Space Storage	20,384	4.5%	n/a	NULL	n/a	n/a	5%	5%	5%
Exxon Mobil Corp.	401,333	3.8%	n/a	NULL	n/a	n/a	8%	8%	4%
F5 Inc.	10,472	0.0%	n/a	NULL	n/a	n/a	9%	9%	0%
FactSet Research	17,281	0.9%	10%	3	10%	1%	11%	11%	1%
Fair Isaac	28,754	0.0%	19%	2	19%	0%	19%	19%	0%
Fastenal Co.	36,936	2.2%	n/a	NULL	n/a	n/a	7%	7%	2%
Federal Rlty. Inv. Trust	8,115	4.2%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
FedEx Corp.	61,536	2.1%	n/a	NULL	n/a	n/a	7%	7%	2%
Fidelity Nat'l Info.	34,857	3.8%	2%	2	2%	4%	23%	n/a	n/a
Fifth Third Bancorp	23,161	4.2%	n/a	NULL	n/a	n/a	4%	4%	4%
First Solar Inc.	17,587	0.0%	n/a	NULL	n/a	n/a	28%	n/a	n/a
FirstEnergy Corp.	20,766	4.6%	6%	3	6%	5%	5%	5%	5%
Fiserv Inc.	79,910	0.0%	15%	4	15%	0%	10%	10%	0%
FLEETCOR Technologies	19,867	0.0%	12%	2	12%	0%	14%	14%	0%
FMC Corp.	7,452	4.2%	n/a	NULL	n/a	n/a	3%	3%	4%
Ford Motor	49,029	5.1%	-9%	3	n/a	n/a	44%	n/a	n/a
Fortinet Inc.	44,598	0.0%	16%	4	16%	0%	22%	n/a	n/a
Fortive Corp.	25,160	0.4%	7%	2	7%	0%	16%	16%	0%
Fox Corp. 'A'	14,260	1.8%	1%	4	1%	2%	8%	8%	2%
Fox Corp. 'B'	n/a	1.9%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Franklin Resources	14,491	4.2%	3%	2	3%	4%	2%	2%	4%
Freep't-McMoRan Inc.	59,282	1.5%	n/a	NULL	n/a	n/a	13%	13%	1%
Gallagher (Arthur J.)	47,522	1.0%	n/a	LTGNumOFes1	n/a	n/a	22%	n/a	n/a
Garmin Ltd.	24,124	2.4%	10%	1	10%	2%	6%	6%	2%
Gartner Inc.	34,785	0.0%	6%	2	6%	0%	13%	13%	0%
GE HealthCare	34,342	0.2%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Gen Digital Inc.	14,608	2.2%	13%	2	13%	2%	12%	12%	2%
Gen'l Dynamics	68,104	2.2%	10%	1	10%	2%	10%	10%	2%
Gen'l Electric	134,274	0.3%	31%	4	n/a	n/a	28%	n/a	n/a
Gen'l Mills	37,389	3.7%	7%	3	7%	4%	5%	5%	4%
Gen'l Motors	49,658	1.0%	4%	2	4%	1%	8%	8%	1%
Generac Holdings	7,800	0.0%	n/a	NULL	n/a	n/a	11%	11%	0%
Genuine Parts	19,191	2.8%	n/a	NULL	n/a	n/a	10%	10%	3%
Gilead Sciences	98,002	3.8%	4%	5	4%	4%	14%	14%	4%
Global Payments	32,404	0.9%	15%	4	15%	1%	14%	14%	1%
Globe Life Inc.	12,746	0.7%	n/a	NULL	n/a	n/a	9%	9%	1%
Goldman Sachs	124,888	2.9%	10%	2	10%	3%	2%	2%	3%
Grainger (W.W.)	40,573	1.0%	n/a	NULL	n/a	n/a	12%	12%	1%
Halliburton Co.	32,632	1.8%	24%	2	n/a	n/a	29%	n/a	n/a
Hartford Fin'l Svcs.	24,047	2.4%	n/a	NULL	n/a	n/a	8%	8%	2%
Hasbro Inc.	6,937	5.6%	n/a	NULL	n/a	n/a	9%	9%	6%
HCA Healthcare	70,865	0.9%	9%	3	9%	1%	10%	10%	1%
Healthpeak Properties	10,491	6.2%	n/a	NULL	n/a	n/a	15%	15%	6%
Henry (Jack) & Assoc.	11,857	1.3%	9%	2	9%	1%	7%	7%	1%
Hershey Co.	36,710	2.7%	8%	3	8%	3%	10%	10%	3%
Hess Corp.	44,774	1.3%	n/a	NULL	n/a	n/a	24%	n/a	n/a
Hewlett Packard Ent.	21,477	3.1%	2%	2	2%	3%	8%	8%	3%
Hilton Worldwide	45,817	0.3%	16%	4	16%	0%	37%	n/a	n/a
Hologic Inc.	16,997	0.0%	n/a	NULL	n/a	n/a	-4%	n/a	n/a
Home Depot	349,009	2.4%	2%	1	2%	2%	7%	7%	2%
Honeywell Int'l	133,772	2.1%	8%	4	8%	2%	11%	11%	2%
Hormel Foods	17,176	3.6%	8%	2	8%	4%	5%	5%	4%
Horton D.R.	50,023	0.8%	5%	3	5%	1%	3%	3%	1%
Host Hotels & Resorts	13,633	4.5%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Howmet Aerospace	21,707	0.4%	21%	2	n/a	n/a	23%	n/a	n/a
HP Inc.	29,441	3.7%	8%	2	8%	4%	9%	9%	4%
Hubbell Inc.	17,219	1.5%	20%	2	20%	2%	13%	13%	2%
Humana Inc.	56,485	0.9%	14%	2	14%	1%	13%	13%	1%
Hunt (J.B.)	20,379	0.9%	5%	2	5%	1%	9%	9%	1%
Huntington Bancshs.	18,058	5.0%	n/a	NULL	n/a	n/a	11%	11%	5%
Huntington Ingalls	10,042	2.1%	8%	2	8%	2%	10%	10%	2%
IDEX Corp.	16,045	1.2%	12%	2	12%	1%	6%	6%	1%
IDEXX Labs.	44,840	0.0%	18%	1	18%	0%	11%	11%	0%
Illinois Tool Works	77,238	2.2%	3%	3	3%	2%	11%	11%	2%
Illumina Inc.	21,630	0.0%	n/a	NULL	n/a	n/a	-3%	n/a	n/a
Incyte Corp.	13,616	0.0%	23%	3	n/a	n/a	32%	n/a	n/a
Ingersoll Rand Inc.	30,307	0.1%	14%	2	14%	0%	13%	13%	0%
Insulet Corp.	14,522	0.0%	36%	2	n/a	n/a	85%	n/a	n/a
Int'l Business Mach.	146,145	4.2%	3%	1	3%	4%	4%	4%	4%

Schedule D5.17

Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
Int'l Flavors & Frag.	20,319	4.1%	-5%	2	n/a	n/a	3%	3%	4%
Int'l Paper	12,660	5.1%	n/a	NULL	n/a	n/a	2%	2%	5%
Intel Corp.	192,924	1.1%	11%	3	11%	1%	-1%	n/a	n/a
Intercontinental Exch.	69,990	1.4%	6%	4	6%	1%	7%	7%	1%
Interpublic Group	12,750	4.1%	5%	3	5%	4%	9%	9%	4%
Intuit Inc.	172,463	0.6%	15%	4	15%	1%	14%	14%	1%
Intuitive Surgical	114,551	0.0%	16%	4	16%	0%	13%	13%	0%
Invesco Ltd.	7,679	4.9%	6%	2	6%	5%	4%	4%	5%
Invitation Homes Inc	20,418	3.1%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
IQVIA Holdings	41,063	0.0%	10%	3	10%	0%	13%	13%	0%
Iron Mountain	19,857	3.8%	5%	1	5%	4%	7%	7%	4%
Jabil Inc.	16,883	0.3%	12%	1	12%	0%	16%	16%	0%
Jacobs Solutions	15,879	0.9%	12%	2	12%	1%	8%	8%	1%
Johnson & Johnson	368,948	3.2%	n/a	NULL	n/a	n/a	5%	5%	3%
Johnson Ctrl. Int'l plc	37,220	2.7%	12%	4	12%	3%	12%	12%	3%
JPMorgan Chase	481,497	2.5%	n/a	NULL	n/a	n/a	9%	9%	3%
Juniper Networks	9,264	3.1%	11%	2	11%	3%	11%	11%	3%
Kellanova	18,136	0.0%	0%	3	n/a	n/a	3%	3%	0%
Kenvue Inc.	40,119	3.8%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Keurig Dr Pepper	45,138	2.7%	7%	3	7%	3%	12%	12%	3%
KeyCorp	13,181	5.8%	n/a	NULL	n/a	n/a	-1%	n/a	n/a
Keysight Technologies	27,854	0.0%	4%	3	4%	0%	9%	9%	0%
Kimberly-Clark	40,154	4.0%	9%	3	9%	4%	6%	6%	4%
Kimco Realty	13,446	4.5%	n/a	NULL	n/a	n/a	11%	11%	5%
Kinder Morgan Inc.	38,987	6.5%	0%	1	0%	6%	18%	18%	6%
KLA Corp.	76,590	0.9%	n/a	NULL	n/a	n/a	11%	11%	1%
Kraft Heinz Co.	43,865	4.5%	5%	3	5%	4%	4%	4%	4%
Kroger Co.	32,400	2.6%	8%	2	8%	3%	6%	6%	3%
L3Harris Technologies	39,135	2.3%	n/a	NULL	n/a	n/a	18%	18%	2%
Laboratory Corp.	18,694	1.3%	-3%	2	n/a	n/a	-3%	n/a	n/a
Lam Research	99,705	1.1%	8%	2	8%	1%	5%	5%	1%
Lamb Weston Holdings	14,987	1.1%	14%	2	14%	1%	15%	15%	1%
Las Vegas Sands	36,328	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Lauder (Estee)	51,390	1.9%	19%	3	19%	2%	3%	3%	2%
Leidos Hldgs.	14,559	1.4%	8%	2	8%	1%	7%	7%	1%
Lennar Corp.	41,741	1.0%	n/a	NULL	n/a	n/a	5%	5%	1%
Lilly (Eli)	541,302	0.9%	29%	5	n/a	n/a	19%	19%	1%
Linde plc	197,040	1.3%	12%	4	12%	1%	9%	9%	1%
Live Nation Entertain.	20,743	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
LKQ Corp.	12,712	2.5%	n/a	NULL	n/a	n/a	7%	7%	3%
Lockheed Martin	109,809	2.9%	11%	3	11%	3%	7%	7%	3%
Loews Corp.	15,400	0.4%	n/a	NULL	n/a	n/a	20%	20%	0%
Lowe's Cos.	127,656	2.0%	4%	1	4%	2%	8%	8%	2%
lululemon athletica	64,017	0.0%	19%	4	19%	0%	17%	17%	0%
LyondellBasell Inds.	31,221	5.2%	-3%	3	n/a	n/a	n/a	n/a	n/a
M&T Bank Corp.	22,232	3.9%	n/a	NULL	n/a	n/a	7%	7%	4%
Marathon Oil Corp.	14,437	2.0%	n/a	NULL	n/a	n/a	23%	n/a	n/a
Marathon Petroleum	59,301	2.2%	-15%	3	n/a	n/a	16%	16%	2%
MarketAxess Holdings	10,492	1.0%	10%	2	10%	1%	10%	10%	1%
Marriott Int'l	63,976	1.0%	18%	3	18%	1%	23%	n/a	n/a
Marsh & McLennan	91,393	1.5%	11%	1	11%	2%	12%	12%	2%
Martin Marietta	30,163	0.6%	23%	2	n/a	n/a	13%	13%	1%
Masco Corp.	15,044	1.8%	4%	2	4%	2%	6%	6%	2%
MasterCard Inc.	393,864	0.6%	21%	4	n/a	n/a	16%	16%	1%
Match Group	9,288	0.0%	26%	5	n/a	n/a	15%	15%	0%
McCormick & Co.	17,962	2.5%	8%	2	8%	2%	5%	5%	2%
McDonald's Corp.	209,604	2.4%	10%	4	10%	2%	11%	11%	2%
McKesson Corp.	59,313	0.6%	10%	2	10%	1%	9%	9%	1%
Medtronic plc	107,225	3.6%	3%	4	3%	4%	8%	8%	4%
Merck & Co.	267,119	2.9%	10%	5	10%	3%	9%	9%	3%
Meta Platforms	897,999	0.0%	35%	4	n/a	n/a	15%	15%	0%
MetLife Inc.	48,548	3.2%	n/a	NULL	n/a	n/a	9%	9%	3%
Mettler-Toledo Int'l	25,738	0.0%	n/a	NULL	n/a	n/a	12%	12%	0%
MGM Resorts Int'l	14,826	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Microchip Technology	47,909	2.1%	n/a	NULL	n/a	n/a	8%	8%	2%
Micron Technology	86,404	0.6%	-3%	2	n/a	n/a	22%	n/a	n/a
Microsoft Corp.	2,754,077	0.8%	15%	6	15%	1%	12%	12%	1%
Mid-America Apt.	15,240	4.5%	n/a	NULL	n/a	n/a	-13%	n/a	n/a
Moderna Inc.	32,838	0.0%	-55%	2	n/a	n/a	-20%	n/a	n/a
Mohawk Inds.	6,505	0.0%	-6%	3	n/a	n/a	1%	1%	0%
Molina Healthcare	20,393	0.0%	16%	2	16%	0%	13%	13%	0%
Molson Coors Beverage	13,220	2.8%	13%	4	13%	3%	42%	n/a	n/a
Mondelez Int'l	94,349	2.5%	9%	3	9%	2%	12%	12%	2%
Monolithic Power Sys.	29,275	0.7%	25%	2	n/a	n/a	15%	15%	1%
Monster Beverage	56,557	0.0%	n/a	NULL	n/a	n/a	11%	11%	0%
Moody's Corp.	69,991	0.8%	14%	3	14%	1%	6%	6%	1%
Morgan Stanley	151,177	3.7%	8%	2	8%	4%	8%	8%	4%
Mosaic Company	11,814	2.3%	-40%	2	n/a	n/a	-3%	n/a	n/a
Motorola Solutions	51,421	1.3%	7%	2	7%	1%	11%	11%	1%
MSCI Inc.	42,723	1.0%	14%	3	14%	1%	13%	13%	1%
Nasdaq Inc.	27,096	1.6%	n/a	NULL	n/a	n/a	6%	6%	2%
NetApp Inc.	18,320	2.4%	7%	1	7%	2%	9%	9%	2%
Netflix Inc.	214,144	0.0%	24%	5	n/a	n/a	13%	13%	0%
Newmont Corp.	32,649	3.9%	-20%	2	n/a	n/a	3%	3%	4%

Schedule D5.17

Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
News Corp. 'A'	13,411	0.9%	12%	3	12%	1%	19%	19%	1%
News Corp. 'B'	14,458	0.8%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
NextEra Energy	122,774	3.4%	8%	2	8%	3%	10%	10%	3%
NIKE Inc. 'B'	185,059	1.2%	14%	4	14%	1%	17%	17%	1%
NiSource Inc.	10,780	4.0%	n/a	NULL	n/a	n/a	7%	7%	4%
Nordson Corp.	14,541	1.1%	13%	1	13%	1%	9%	9%	1%
Norfolk Southern	51,962	2.4%	3%	3	3%	2%	9%	9%	2%
Northern Trust Corp.	17,203	3.6%	n/a	NULL	n/a	n/a	3%	3%	4%
Northrop Grumman	68,969	1.7%	n/a	NULL	n/a	n/a	9%	9%	2%
Norwegian Cruise Line	8,453	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
NRG Energy	11,378	3.1%	n/a	NULL	n/a	n/a	-3%	n/a	n/a
Nucor Corp.	43,192	1.2%	n/a	NULL	n/a	n/a	2%	2%	1%
NVIDIA Corp.	1,187,861	0.0%	102%	5	n/a	n/a	43%	n/a	n/a
NVR Inc.	22,329	0.0%	-6%	2	n/a	n/a	4%	4%	0%
NXP Semi. NV	57,834	1.8%	10%	3	10%	2%	9%	9%	2%
O'Reilly Automotive	56,655	0.0%	12%	3	12%	0%	11%	11%	0%
Occidental Petroleum	53,231	1.5%	-16%	2	n/a	n/a	17%	17%	1%
Old Dominion Freight	43,893	0.4%	8%	3	8%	0%	9%	9%	0%
Omnicom Group	16,969	3.3%	9%	3	9%	3%	7%	7%	3%
ON Semiconductor	34,951	0.0%	5%	2	5%	0%	15%	15%	0%
ONEOK Inc.	39,875	5.7%	n/a	NULL	n/a	n/a	15%	15%	6%
Oracle Corp.	286,204	1.5%	11%	3	11%	2%	10%	10%	2%
Otis Worldwide	36,129	1.5%	10%	1	10%	2%	11%	11%	2%
PACAR Inc.	50,161	3.1%	n/a	NULL	n/a	n/a	17%	17%	3%
Packaging Corp.	14,564	3.1%	n/a	NULL	n/a	n/a	9%	9%	3%
Palo Alto Networks	92,792	0.0%	22%	6	n/a	n/a	n/a	n/a	n/a
Paramount Global	10,106	1.3%	-8%	4	n/a	n/a	-1%	n/a	n/a
Parker-Hannifin	57,740	1.4%	11%	2	11%	1%	12%	12%	1%
Paychex Inc.	46,183	3.0%	9%	2	9%	3%	10%	10%	3%
Paycom Software	11,773	0.7%	15%	3	15%	1%	20%	20%	1%
PayPal Holdings	66,679	0.0%	18%	5	18%	0%	12%	12%	0%
Pentair plc	11,667	1.3%	9%	4	9%	1%	13%	13%	1%
PepsiCo Inc.	227,824	3.1%	9%	3	9%	3%	7%	7%	3%
Pfizer Inc.	155,999	6.1%	-15%	3	n/a	n/a	2%	2%	6%
PG&E Corp.	35,810	0.2%	11%	2	11%	0%	30%	n/a	n/a
Philip Morris Int'l	142,803	5.7%	7%	3	7%	6%	6%	6%	6%
Phillips 66	58,985	3.3%	n/a	NULL	n/a	n/a	16%	16%	3%
Pinnacle West Capital	8,016	5.0%	6%	2	6%	5%	3%	3%	5%
Pioneer Natural Res.	52,966	4.0%	-4%	2	n/a	n/a	9%	9%	4%
PNC Financial Serv.	59,620	4.1%	n/a	NULL	n/a	n/a	7%	7%	4%
Pool Corp.	15,108	1.1%	-9%	2	n/a	n/a	6%	6%	1%
PPG Inds.	34,502	1.8%	16%	3	16%	2%	3%	3%	2%
PPL Corp.	19,467	3.6%	n/a	NULL	n/a	n/a	8%	8%	4%
Price (T. Rowe) Group	23,691	4.7%	-5%	1	n/a	n/a	2%	2%	5%
Principal Fin'l Group	18,963	3.3%	n/a	NULL	n/a	n/a	6%	6%	3%
Procter & Gamble	339,933	2.6%	8%	3	8%	3%	6%	6%	3%
Progressive Corp.	91,055	0.3%	n/a	NULL	n/a	n/a	12%	12%	0%
Prologis	120,442	2.8%	n/a	NULL	n/a	n/a	3%	3%	3%
Prudential Fin'l	37,257	5.1%	11%	1	11%	5%	5%	5%	5%
PTC Inc.	20,086	0.0%	11%	4	11%	0%	16%	16%	0%
Public Serv. Enterprise	30,249	3.9%	5%	2	5%	4%	4%	4%	4%
Public Storage	51,313	4.1%	n/a	NULL	n/a	n/a	8%	8%	4%
PulteGroup Inc.	22,063	0.8%	n/a	NULL	n/a	n/a	9%	9%	1%
Qorvo Inc.	10,584	0.0%	10%	2	10%	0%	8%	8%	0%
Qualcomm Inc.	156,591	2.3%	6%	3	6%	2%	6%	6%	2%
Quanta Services	30,928	0.2%	n/a	NULL	n/a	n/a	16%	16%	0%
Quest Diagnostics	15,094	2.1%	-1%	2	n/a	n/a	3%	3%	2%
Ralph Lauren	9,417	2.1%	13%	3	13%	2%	13%	13%	2%
Raymond James Fin'l	23,373	1.6%	n/a	NULL	n/a	n/a	13%	13%	2%
Realty Income Corp.	33,525	5.5%	n/a	NULL	n/a	n/a	6%	6%	6%
Regency Centers Corp.	11,193	4.0%	n/a	NULL	n/a	n/a	16%	16%	4%
Regeneron Pharmac.	91,671	0.0%	2%	4	2%	0%	-1%	n/a	n/a
Regions Financial	17,801	5.3%	n/a	NULL	n/a	n/a	9%	9%	5%
Republic Services	51,109	1.3%	n/a	NULL	n/a	n/a	13%	13%	1%
ResMed Inc.	25,588	1.1%	n/a	NULL	n/a	n/a	9%	9%	1%
Revvity Inc.	12,835	0.3%	n/a	NULL	n/a	n/a	-4%	n/a	n/a
Robert Half Inc.	9,228	2.5%	n/a	NULL	n/a	n/a	7%	7%	2%
Rockwell Automation	34,849	1.7%	10%	4	10%	2%	10%	10%	2%
Rollins Inc.	20,494	1.2%	15%	1	15%	1%	10%	10%	1%
Roper Tech.	57,143	0.6%	11%	1	11%	1%	8%	8%	1%
Ross Stores	45,357	1.1%	12%	4	12%	1%	12%	12%	1%
Royal Caribbean	30,956	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
RTX Corp.	117,390	2.9%	11%	3	11%	3%	15%	15%	3%
S&P Global	135,537	0.8%	13%	3	13%	1%	8%	8%	1%
Salesforce Inc.	252,182	0.0%	27%	6	n/a	n/a	18%	18%	0%
SBA Communications	26,630	1.4%	14%	2	14%	1%	22%	n/a	n/a
Schein (Henry)	9,537	0.0%	9%	2	9%	0%	9%	9%	0%
Schlumberger Ltd.	74,779	2.0%	29%	2	n/a	n/a	26%	n/a	n/a
Schwab (Charles)	122,246	1.6%	5%	3	5%	2%	10%	10%	2%
Seagate Technology plc	17,122	3.4%	213%	2	n/a	n/a	7%	7%	3%
Sempra Energy	46,029	3.3%	n/a	NULL	n/a	n/a	7%	7%	3%
ServiceNow Inc.	142,267	0.0%	27%	5	n/a	n/a	61%	n/a	n/a
Sherwin-Williams	77,878	0.8%	14%	2	14%	1%	11%	11%	1%
Simon Property Group	47,353	5.5%	n/a	NULL	n/a	n/a	4%	4%	5%

Schedule D5.17

Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
Skyworks Solutions	17,476	2.7%	15%	2	15%	3%	-3%	n/a	n/a
Smith (A.O.)	12,129	1.6%	n/a	NULL	n/a	n/a	11%	11%	2%
Smucker (J.M.)	12,497	3.5%	7%	3	7%	4%	6%	6%	4%
Snap-on Inc.	14,997	2.5%	5%	2	5%	2%	8%	8%	2%
Southern Co.	76,005	4.0%	13%	4	13%	4%	7%	7%	4%
Southwest Airlines	17,329	1.2%	7%	2	7%	1%	n/a	n/a	n/a
Stanley Black & Decker	14,741	3.4%	29%	3	n/a	n/a	4%	4%	3%
Starbucks Corp.	108,481	2.4%	13%	2	13%	2%	15%	15%	2%
State Street Corp.	23,468	3.7%	17%	4	17%	4%	7%	7%	4%
Steel Dynamics	19,663	1.4%	4%	3	4%	1%	-2%	n/a	n/a
STERIS plc	21,235	1.0%	n/a	NULL	n/a	n/a	10%	10%	1%
Stryker Corp.	109,529	1.1%	n/a	NULL	n/a	n/a	9%	9%	1%
Synchrony Financial	15,447	2.7%	11%	5	11%	3%	5%	5%	3%
Synopsys Inc.	83,930	0.0%	n/a	NULL	n/a	n/a	16%	16%	0%
Sysco Corp.	36,933	2.7%	18%	2	18%	3%	16%	16%	3%
T-Mobile US	179,572	1.7%	12%	2	12%	2%	20%	20%	2%
Take-Two Interactive	26,853	0.0%	-5%	1	n/a	n/a	59%	n/a	n/a
Tapestry Inc.	8,316	3.8%	60%	2	n/a	n/a	13%	13%	4%
Targa Resources	19,136	3.5%	11%	2	11%	4%	n/a	n/a	n/a
Target Corp.	63,193	3.2%	21%	1	n/a	n/a	11%	11%	3%
TE Connectivity	43,520	1.7%	20%	3	n/a	n/a	9%	9%	2%
Teledyne Technologies	19,911	0.0%	n/a	NULL	n/a	n/a	10%	10%	0%
Teleflex Inc.	11,636	0.6%	n/a	NULL	n/a	n/a	11%	11%	1%
Teradyne Inc.	15,877	0.5%	n/a	NULL	n/a	n/a	5%	5%	0%
Tesla Inc.	785,658	0.0%	8%	3	8%	0%	28%	n/a	n/a
Texas Instruments	149,983	3.2%	2%	4	2%	3%	4%	4%	3%
Textron Inc.	15,554	0.1%	10%	2	10%	0%	16%	16%	0%
Thermo Fisher Sci.	200,693	0.3%	18%	2	18%	0%	8%	8%	0%
TJX Companies	102,734	1.5%	2%	4	2%	1%	17%	17%	1%
Tractor Supply	22,756	2.1%	13%	4	13%	2%	12%	12%	2%
Trane Technologies plc	54,284	1.3%	6%	3	6%	1%	15%	15%	1%
TransDigm Group	54,291	0.0%	14%	3	14%	0%	24%	n/a	n/a
Travelers Cos.	41,989	2.2%	16%	2	16%	2%	8%	8%	2%
Trimble Inc.	12,793	0.0%	15%	1	15%	0%	6%	6%	0%
Truist Fin'l	47,732	5.9%	n/a	NULL	n/a	n/a	6%	6%	6%
Tyler Technologies	19,694	0.0%	n/a	NULL	n/a	n/a	11%	11%	0%
Tyson Foods 'A'	18,213	3.8%	11%	1	11%	4%	-13%	n/a	n/a
U.S. Bancorp	66,109	4.6%	n/a	NULL	n/a	n/a	4%	4%	5%
Uber Technologies	124,603	0.0%	6%	2	6%	0%	n/a	n/a	n/a
UDR Inc.	12,186	4.9%	n/a	NULL	n/a	n/a	17%	17%	5%

Schedule D5.17

Panel B: Estimation of S&P 500 Cost of Equity- DDM

Company	VL Market Cap (\$Millions)	VL Indicated Annual Dividend Yield	IBES Growth Rates				Value Line Growth Rates		
			Growth Rate	# of Analyst Estimates (Consensus)	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR	Growth Rate	Growth Rate Filtered Between 0 and 20%	Dividend Yield for companies with valid GR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Market Cap Weighted Average			14.80%	2.9	10.94%	1.35%	12.85%	10.76%	1.55%
Ulta Beauty	23,564	0.0%	7%	4	7%	0%	14%	14%	0%
Under Armour 'C'	3,846	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Union Pacific	144,979	2.4%	6%	3	6%	2%	8%	8%	2%
United Airlines Hldgs.	13,508	0.0%	59%	3	n/a	n/a	n/a	n/a	n/a
United Parcel Serv.	133,699	4.1%	-5%	4	n/a	n/a	3%	3%	4%
United Rentals	37,814	1.1%	15%	3	15%	1%	17%	17%	1%
UnitedHealth Group	477,235	1.5%	13%	3	13%	1%	13%	13%	1%
Universal Health 'B'	10,108	0.5%	13%	3	13%	1%	6%	6%	1%
V.F. Corp.	6,977	2.0%	1%	3	1%	2%	3%	3%	2%
Valero Energy	45,124	3.1%	-21%	3	n/a	n/a	10%	10%	3%
Ventas Inc.	19,349	4.0%	n/a	NULL	n/a	n/a	23%	n/a	n/a
Veralto Corp.	n/a	0.0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
VeriSign Inc.	20,918	0.0%	n/a	NULL	n/a	n/a	13%	13%	0%
Verisk Analytics	33,845	0.6%	11%	3	11%	1%	9%	9%	1%
Verizon Communic.	156,813	7.1%	1%	4	1%	7%	2%	2%	7%
Vertex Pharmac.	103,196	0.0%	11%	5	11%	0%	10%	10%	0%
Viatis Inc.	12,536	5.0%	1%	3	1%	5%	-3%	n/a	n/a
Vici Properties	19,573	5.3%	-3%	2	n/a	n/a	8%	8%	5%
Visa Inc.	478,739	0.8%	n/a	NULL	n/a	n/a	14%	14%	1%
Vulcan Materials	29,395	0.8%	14%	4	14%	1%	10%	10%	1%
Wabtec Corp.	22,371	0.5%	21%	2	n/a	n/a	14%	14%	1%
Walgreens Boots	21,937	7.6%	-8%	2	n/a	n/a	1%	1%	8%
Walmart Inc.	413,941	1.5%	8%	3	8%	2%	7%	7%	2%
Warner Bros. Discovery	28,427	0.0%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Waste Management	70,801	1.6%	10%	2	10%	2%	7%	7%	2%
Waters Corp.	19,109	0.0%	4%	4	4%	0%	6%	6%	0%
WEC Energy Group	25,799	4.1%	5%	2	5%	4%	6%	6%	4%
Wells Fargo	179,185	2.8%	n/a	NULL	n/a	n/a	11%	11%	3%
Welltower Inc.	43,425	2.9%	n/a	NULL	n/a	n/a	12%	12%	3%
West Pharmac. Svcs.	25,862	0.2%	4%	2	4%	0%	7%	7%	0%
Western Digital	16,009	0.0%	n/a	NULL	n/a	n/a	3%	3%	0%
WestRock Co.	11,005	2.8%	n/a	NULL	n/a	n/a	10%	10%	3%
Weyerhaeuser Co.	24,897	2.2%	n/a	NULL	n/a	n/a	-2%	n/a	n/a
Whirlpool Corp.	6,416	6.4%	n/a	NULL	n/a	n/a	-1%	n/a	n/a
Williams Cos.	42,193	5.2%	2%	2	2%	5%	11%	11%	5%
Willis Towers Wat. plc	24,334	1.4%	n/a	NULL	n/a	n/a	9%	9%	1%
Wynn Resorts	10,038	1.1%	n/a	NULL	n/a	n/a	n/a	n/a	n/a
Xcel Energy Inc.	33,823	3.6%	6%	2	6%	4%	6%	6%	4%
Xylem Inc.	26,409	1.2%	n/a	NULL	n/a	n/a	12%	12%	1%
Yum! Brands	36,131	1.9%	14%	4	14%	2%	12%	12%	2%
Zebra Techn. 'A'	13,436	0.0%	n/a	NULL	n/a	n/a	-3%	n/a	n/a
Zimmer Biomet Hldgs.	25,080	0.8%	7%	4	7%	1%	7%	7%	1%
Zions Bancorp.	6,302	4.0%	n/a	NULL	n/a	n/a	4%	4%	4%
Zoetis Inc.	89,437	0.9%	10%	2	10%	1%	9%	9%	1%

Sources and Notes:

[1] and [7]: Value Line Investment Analyzer as of 12/31/2023.

[3]: Thomson Reuters as of 12/31/2023.

[6],[9]: Excludes non-dividend paying companies.

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Exhibit A-14 Schedule D5.18
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Revised Schedule D5.18: Electric Sample Characteristics

Company	Revenue		Regulated Assets	Market Cap. (Q3 2023)	Value Line Beta	Long-Term Growth Estimate	Credit Ratings		Generation		Per Share CapEx		
	Annual (Q3 2023)	From Industrial Load					S&P	Moody's	Nuclear	Coal	2023	2024	2026-2028
	(\$MM)	(%)							(%)	(%)	(\$MM)	(\$MM)	(\$MM)
	[1]	[2]					[7]	[8]	[9]	[10]	[11]	[12]	[13]
ALLETE	\$1,750	43%	MR	\$3,200	0.95	8.1%	BBB	Baa1	0	28%	\$5.95	\$5.95	\$7.25
Alliant Energy	\$4,100	29%	R	\$12,600	0.90	6.7%	A-	Baa2	0	32%	\$5.80	\$5.80	\$5.40
Amer. Elec. Power	\$19,500	18%	R	\$41,300	0.80	3.7%	A-	Baa2	n/a	n/a	\$15.35	\$14.15	\$14.00
Ameren Corp.	\$8,000	8%	R	\$20,400	0.90	5.4%	BBB+	Baa1	11%	73%	\$12.90	\$12.55	\$13.00
Avista Corp.	\$1,700	10%	R	\$2,400	0.90	5.9%	BBB	Baa2	0	31%	\$6.00	\$6.35	\$6.75
Black Hills	\$2,600	23%	R	\$3,300	1.00	n/a	BBB+	Baa2	0	35%	\$9.30	\$9.50	\$9.25
CMS Energy Corp.	\$8,500	15%	R	\$16,700	0.85	7.7%	BBB+	Baa2	0	29%	\$8.00	\$9.50	\$9.75
CenterPoint Energy	\$9,200	n/a	R	\$17,600	1.15	n/a	BBB+	Baa2	n/a	n/a	\$6.65	\$7.05	\$9.00
Duke Energy	\$29,650	13%	R	\$67,700	0.85	n/a	BBB+	Baa2	30%	18%	\$16.75	\$17.60	\$16.75
Edison Int'l	\$17,350	3%	R	\$24,000	1.00	4.9%	BBB	Baa2	9%	0%	\$15.25	\$15.75	\$17.00
Entergy Corp.	\$12,225	27%	R	\$21,500	0.95	n/a	BBB+	Baa2	22%	9%	\$23.00	\$19.00	\$19.75
Eversource Inc.	\$5,780	15%	R	\$11,700	0.95	2.5%	BBB+	Baa2	17%	54%	\$9.20	\$9.25	\$9.50
Exelon Corp.	\$19,700	17%	MR	\$38,300	n/a	10.1%	BBB+	Baa2	n/a	n/a	\$6.80	\$6.80	\$7.00
IDACORP Inc.	\$1,675	22%	R	\$4,900	0.85	n/a	BBB	Baa2	0%	20%	\$14.00	\$16.00	\$11.00
MGE Energy	\$740	3%	R	\$2,700	0.75	n/a			0%	35%	\$4.65	\$4.00	\$5.25
NextEra Energy	\$27,600	45%	MR	\$116,000	0.95	8.2%	A-	Baa1	21%	0%	\$9.50	\$9.50	\$9.75
NorthWestern Corp.	\$1,500	5%	R	\$3,000	0.95	n/a	BBB	Baa2	0%	28%	\$8.50	\$7.75	\$7.00
OGE Energy	\$3,400	11%	R	\$7,000	1.05	n/a	BBB+	(P)Baa1	0%	21%	\$4.75	\$4.75	\$4.75
Otter Tail Corp.	\$1,350	30%	R	\$3,100	0.90	n/a	BBB	Baa2	0%	38%	\$5.90	\$6.00	\$6.25
Pinnacle West Capital	\$4,625	41%	R	\$8,300	0.95	5.9%	BBB+	Baa1	24%	20%	\$14.50	\$15.00	\$15.00
Public Serv. Enterprise	\$11,900	9%	MR	\$30,000	0.90	5.2%	BBB+	Baa2	n/a	n/a	\$7.20	\$7.20	\$7.25
Sempra Energy	\$17,350	n/a	R	\$43,100	1.00	n/a	BBB+	Baa2	n/a	n/a	\$8.55	\$8.55	\$9.00
Southern Co.	\$27,500	19%	R	\$72,800	0.90	7.1%	BBB+	Baa2	16%	20%	\$7.85	\$7.85	\$7.50
WEC Energy Group	\$9,375	21%	R	\$25,900	0.85	5.5%	A-	Baa1	0%	36%	\$9.30	\$9.30	\$9.25
Xcel Energy Inc.	\$15,100	48%	R	\$31,800	0.85	6.3%	A-	Baa1	13%	23%	\$9.00	\$9.25	\$9.50
DTE Electric	\$6,397	18%	R	n/a	n/a	n/a	A-	A2	19%	45%	n/a	n/a	n/a
Electric Sample	\$10,487	21%	R	\$25,172	0.92	6%	BBB+	Baa2	8%	28%	\$9.79	\$9.78	\$9.84
Median	\$8,500	18%	R	\$17,600	0.90	6%	BBB+	Baa2	0%	28%	\$8.55	\$9.25	\$9.25

Case No. U-21534
Exhibit A-14 Schedule D5.18
page 2 of 2

Revised Schedule D5.18: Electric Sample Characteristics

Electric Sample Sources:

[1]-[2]: Value Line as of 12/21/2023
[3]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[4]-[5]: Value Line as of 12/21/2023
[6]: Eikon as of 1/9/2024
[7]: S&P as of 1/30/2024
[8]: Moody's as of 12/21/2023
[9]-[16]: Value Line as of 12/21/2023
[17]: [11]*[14]
[18]: [12]*[15]
[19]: [13]*[16]
[20]: ([18]+[19])/2
[21]: [17]+[18]+[20]
[22]: Value Line as of 12/21/2023

DTE Electric Sources:

[1]: DTE 2022 10-K, p.32
[2]: DTE 2022 10-K, p.33 - Calculated by dividing Industrial Total by Total DTE Electric Sales
[3]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[7]: S&P as of 1/30/2024
[8]: Moody's as of 12/21/2023
[9]-[10]: DTE Business Update Presentation, Slide 18
[17]: DTE Business Update Presentation, Slide 14
[18]-[20]: DTE Business Update Presentation, Slide 4; \$20B total CapEx from 2024-2028; \$20B / 5 years = \$4,000MM per year
[22]: DTE 2022 10-K, p.89

Schedule D5.19: Available Regulatory Mechanisms

Ticker	Company	Regulated Operations Jurisdiction	Decoupling		PBR	Forward Test Year	Multi-Year Plans	Riders		
			Full	Partial				Renewables/ Non-Traditional Generation	Delivery Infrastructure	Environmental compliance
		[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]
ALE	ALLETE	MN	-	-	MN	MN	-	MN	-	-
LNT	Alliant Energy	IA, WI	-	-	-	IA, WI	WI	IA	-	IA
AEP	Amer. Elec. Power	AR, IN, KY, LA, MI, OH, OK, TN, TX, VA, WV	-	AR, IN, KY, LA, MI, OH, OK	IN, MI, OH, OK, TX	MI, TN, TX	IN, OH	IN, MI, OH, OK	IN, OH, OK, TX	AR, IN, KY, VA, WV
AEE	Ameren Corp.	IL, MO	-	IL, MO	IL, MO	-	-	IL, MO	IL, MO	IL
AVA	Avista Corp.	AK, ID, WA, OR	ID, WA	OR	OR	-	-	-	-	-
BKH	Black Hills	AR, CO, IA, KS, NE, SD, WY	AR	KS, WY	CO	IA	-	CO	AR, CO, IA, KS, NE, WY	SD
CMS	CMS Energy Corp.	MI	-	MI	MI	MI	-	MI	-	-
CNP	CenterPoint Energy	IN, LA, MN, OH, TX	IN	IN, LA, MN	IN, MN, OH, TX	MN, TX	-	-	IN, OH, TX	IN
DOM	Dominion Energy	n/a	n/a	n/a	n/a	-	-	n/a	n/a	n/a
DUK	Duke Energy	FL, IN, KY, NC, OH, SC, TN	NC	IN, KY, OH, SC, TN	IN, NC, OH	TN	FL, OH, SC	FL, IN, NC, OH	IN, KY, NC, OH, TN	FL, IN, KY, NC, OH, SC
EIX	Edison Int'l	CA	CA	-	CA	CA	CA	-	-	-
ETR	Entergy Corp.	AR, LA, MS, TX	-	AR, LA, MS	TX	TX	LA	AR, LA	AR, LA, TX	LA
EVRG	Evergy Inc.	KS, MO	-	KS, MO	MO	-	-	KS, MO	KS, MO	KS
EXC	Exelon Corp.	DE, DC, IL, MD, NJ, PA	MD	DC, NJ	IL, MD, NJ, PA	PA	-	DC, IL	DE, DC, IL, MD, NJ, PA	DE, IL, NJ
IDA	IDACORP Inc.	ID, OR	ID	-	OR	-	-	-	-	-
MGEE	MGE Energy	WI	-	-	-	WI	-	WI	-	-
NEE	NextEra Energy	FL, TX	-	-	TX	TX	FL	FL	FL, TX	FL
NWE	NorthWestern Corp.	MT, NE, SD	-	-	-	-	-	-	-	-
OGE	OGE Energy	AR, OK	-	AR, OK	OK	-	-	AR	AR, OK	AR, OK
OTTR	Otter Tail Corp.	MN, ND, SD	-	-	MN	MN	-	MN, ND	ND, SD	MN, ND, SD
PNW	Pinnacle West Capital	AZ	-	AZ	AZ	-	-	AZ	-	AZ
POR	Portland General	OR	-	-	OR	-	-	OR	-	OR
PPL	PPL Corp.	KY, PA, RI, VA	RI	KY	PA	PA	-	-	KY, PA, RI	KY, RI
PEG	Public Serv. Enterprise	NJ	-	NJ	NJ	-	-	-	NJ	NJ
SRE	Sempra Energy	CA, TX	CA	-	CA, TX	CA, TX	CA	-	TX	-
SO	Southern Co.	AL, GA, IL, MS, TN, VA	TN	IL, MS, VA	GA, IL	GA, MS, TN	GA	AL	GA, IL, VA	AL, GA, IL, MS
WEC	WEC Energy Group	IL, MI, MN, WI	-	IL, MN	IL, MI, MN	MI, MN, WI	WI	MI, WI	IL, MI, MN	IL
XEL	Xcel Energy Inc.	CO, MN, NM, ND, SD, TX, WI	-	CO, MN, SD	CO, MN, NM, TX	MN, TX, WI	MN	CO, MN, NM, ND	CO, MN, ND, SD	MN, SD
	# of States	[1] 43	9	24	20	12	9	21	29	25
	# of Subsidiaries	[2] 142	18	52			21	36	65	48
	# of Proxy Companies	[3] 28	11	18	25	18	10	20	18	20
DTE	DTE Electric	MI	-	-	MI	MI	-	MI	-	-

Sources and Notes:

[a] : Data From S&P Market Intelligence, as of 6/20/2023.

[b], [c], [g], [h], [i]: Data From S&P Market Intelligence, as of 6/20/2023.

[d] : Various Sources. Available upon request.

[e] : Data from S&P Market Intelligence, accessed 5/20/2022.

[f] : Data from company 10Ks.

[1] : Sum of unique states per column.

[2] : Sum of member states across companies.

[3] : Total parent companies represented in each column.

Michigan Public Service Commission
DTE Electric Company
Annual Service Area Sales By Major Customer Classes And System Output
2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E1
Witness: M.B. Leuker
Page: 1 of 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line	Annual Sales - GWh						Losses & Company Use		System Output	
	No.	Year	Residential	Small C&I	Large C&I	Other ⁽¹⁾	Total	(GWh)		% Of Output
1	2023 Forecast ²		14,577	10,550	18,311	204	43,642	3,325	7.1%	46,967
2	2023 Forecast T-N ³		15,366	10,749	18,422	204	44,740	NA	NA	NA
3	Projected Period		15,274	10,678	18,044	193	44,189	3,152	6.7%	47,341
4	2024		15,290	10,727	18,122	195	44,333	3,162	6.7%	47,495
5	2025		15,274	10,678	18,044	193	44,189	3,152	6.7%	47,341
6	2026		15,325	10,632	17,849	192	43,999	3,146	6.7%	47,145
7	2027		15,402	10,604	17,632	191	43,830	3,143	6.7%	46,973
8	2028		15,578	10,618	17,782	192	44,170	3,167	6.7%	47,337

¹⁾ Other Sales forecast for 2023-2028 is comprised of Street Lighting and Traffic Signals and is sponsored by Witness Robert Bellini

²⁾ 2023 Forecast includes 10 months of actuals and 2 months of forecast

³⁾ 2023 Forecast includes 10 months of actuals and 2 months of forecast and uses 2008-2022 15-year weather normalization

Michigan Public Service Commission
DTE Electric Company
Annual Bundled Sales By Major Customer Classes And System Output
2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E1
Witness: M.B. Leuker
Page: 2 of 3

Line	No.	Year	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			<u>Annual Sales - GWh</u>					<u>Total</u>	<u>Losses & Company Use</u>	<u>% Of</u>	<u>System Output</u>
			<u>Residential</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Other ⁽¹⁾</u>			<u>(GWh)</u>	<u>Output</u>	<u>(GWh)</u>
1		2023 Forecast ²	14,577	9,751	14,723	204	39,255		2,896	6.9%	42,151
2		2023 Forecast T-N ³	15,366	9,950	14,834	204	40,354		NA	NA	NA
3		Projected Period	15,274	9,856	14,432	193	39,756		2,927	6.9%	42,683
4		2024	15,290	9,901	14,492	195	39,878		2,936	6.9%	42,814
5		2025	15,274	9,856	14,432	193	39,756		2,927	6.9%	42,683
6		2026	15,325	9,813	14,249	192	39,580		2,922	6.9%	42,501
7		2027	15,402	9,789	14,048	191	39,430		2,920	6.9%	42,350
8		2028	15,578	9,805	14,211	192	39,786		2,945	6.9%	42,732

¹⁾ Other Sales forecast for 2023-2028 is comprised of Street Lighting and Traffic Signals and is sponsored by Witness Robert Bellini

²⁾ 2023 Forecast includes 10 months of actuals and 2 months of forecast

³⁾ 2023 Forecast includes 10 months of actuals and 2 months of forecast and uses 2008-2022 15-year weather normalization

Michigan Public Service Commission
DTE Electric Company
Annual Electric Choice Sales By Major Customer Classes
2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E1
Witness: M.B. Leuker
Page: 3 of 3

	(a)	(b)	(c)	(d)	(e)	(f)
	Annual Sales - GWh					
Line No.	Year	Residential	Small C&I	Large C&I	Other	Total
1	2023 Forecast	0	799	3,588	0	4,387
2	Projected Period	0	822	3,612	0	4,434
3	2024	0	826	3,629	0	4,455
4	2025	0	822	3,612	0	4,434
5	2026	0	819	3,600	0	4,419
6	2027	0	816	3,584	0	4,400
7	2028	0	813	3,571	0	4,383

Michigan Public Service Commission
DTE Electric Company
Annual Service Area System Output,
Maximum Demand And Load Factor
2018-2022 Historical; 2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E2
Witness: M.B. Leuker
Page: 1 of 2

(a)		(b)	(c)	(d)	(e)	(f)
<u>Line No.</u>	<u>Year</u>	<u>System Output (GWh)</u>	<u>Maximum Demand (MW)</u>	<u>Annual Load Factor %</u>	<u>Range Of Probable Max. Demand (MW)</u>	
					<u>Low (10%)</u>	<u>High (90%)</u>
1	2018	52,172	11,418	52.2		
2	2019	50,116	10,630	53.7		
3	2020	47,851	11,005	49.6		
4	2021	49,380	10,992	51.3		
5	2022	48,985	10,933	51.1		
6	2022 T-N	NA	10,959	NA		
7	2023 Forecast	46,967	10,340	51.9		
8	Projected Period	47,341	10,911	49.5	9,796	12,027
9	2024	47,495	10,962	49.5	10,169	11,754
10	2025	47,341	10,911	49.5	9,796	12,027
11	2026	47,145	10,882	49.5	9,520	12,245
12	2027	46,973	10,860	49.4	9,290	12,430
13	2028	47,337	10,905	49.6	9,142	12,668

Michigan Public Service Commission
DTE Electric Company
Annual Bundled System Output, Maximum Demand And Load Factor
2018-2022 Historical; 2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E2
Witness: M.B. Leuker
Page: 2 of 2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Year	System Output	Non-Coincident Maximum Demand	Annual Load Factor	Range Of Probable Max. Demand (MW)		Coincident Maximum Demand	Electric Choice Impact	
		(GWh)	(MW)	%	Low (10%)	High (90%)	(MW) ¹	(MW)	
1	2018	47,129	10,520	51.0			10,520	897	
2	2019	44,940	9,840	52.1			9,840	790	
3	2020	43,196	10,337	47.7			10,337	668	
4	2021	44,580	10,186	50.0			10,186	806	
5	2022	43,990	10,182	49.3			10,182	752	
6	2022 T-N	NA	10,207	NA			10,207	752	
7	2023 Forecast	42,151	9,573	50.3			9,573	767	
8	Projected Period	42,683	10,157	48.0	8,965	11,348	10,157	755	
9	2024	42,814	10,206	47.9	9,359	11,052	10,206	756	
10	2025	42,683	10,157	48.0	8,965	11,348	10,157	755	
11	2026	42,501	10,129	47.9	8,674	11,584	10,129	754	
12	2027	42,350	10,105	47.8	8,429	11,781	10,105	755	
13	2028	42,732	10,151	48.1	8,269	12,034	10,151	754	

Michigan Public Service Commission
DTE Electric Company
Projected Period Known And Measurable Changes To Sales (GWh)

Case No. : U-21534
Exhibit: A-15
Schedule: E3
Witness: M.B. Leuker
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	<u>2022 Sales</u>		<u>Weather</u>	<u>Economic/ Production</u>	<u>Emerging Tech</u>	<u>Change In Electric Choice</u>	<u>Usage Changes ¹</u>	<u>Adds & Losses</u>	<u>Total Change</u>	<u>Projected Period Sales</u>	
No.	<u>Actual</u>	<u>T-N</u>								<u>Jan-25</u>	<u>Dec-25</u>
1 <u>BUNDLED</u>											
2 Residential	15,844	15,689	-156	-36	88	0	-467	0	-570	15,274	
3											
4 Comm. Secondary	10,014	9,956	-58	140	37	12	-289	0	-158	9,856	
7											
11 Comm. Pri & Industrial	14,830	14,777	-53	419	18	40	-976	156	-397	14,432	
12											
13 Other	210	210	0	0	0	0	-17	0	-17	193	
14											
15 Total	40,898	40,631	-267	522	144	52	-1,749	156	-1,142	39,756	
16											
17											
18 <u>ELECTRIC CHOICE</u>											
19 Residential	0	0	0	NA	NA	0	NA	0	0	0	
20											
21 Comm. Secondary	834	834	0	NA	NA	-12	NA	0	-12	822	
24											
28 Comm. Pri & Industrial	3,651	3,651	0	NA	NA	-40	NA	0	-40	3,612	
29											
30 Other	0	0	0	NA	NA	0	NA	0	0	0	
31											
32 Total	4,486	4,486	0	NA	NA	-52	NA	0	-52	4,434	

1) Usage changes includes energy waste reduction, changes in appliance saturation, and other miscellaneous consumption changes

Michigan Public Service Commission
DTE Electric Company
Summary Of Economic Outlook
2018-2022 Historical; 2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E4
Witness: M.B. Leuker
Page: 1 of 1

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Year	Real Gross State Product (Billions \$2012)	Real Personal Income (Billions \$2012)	Consumer Price Index (1982-84=100)	Households (Thousands)	Population (Thousands)	U.S. Car & Truck Production Total (Th. Units)	Car & Truck Production Detroit Area (Th. Units)	U.S. Car & Truck Prod. Detroit 3 (Th. Units)	Manufacturing Employment (Thousands)
1	2018	466.4	467.6	251.1	4048.01	10071.16	11030.8	1557.2	5770.2	629.3
2	2019	467.8	472.6	255.7	4066.06	10078.08	10597.6	1553.4	5267.1	627.3
3	2020	447.9	519.2	258.8	4034.13	10061.78	8623.0	1073.7	4281.2	551.9
4	2021	483.9	516.0	271.0	4034.62	10035.31	8910.9	1312.5	4285.3	585.0
5	2022	490.4	492.4	292.7	4067.05	10036.59	9759.4	1365.0	4765.0	603.7
6	2023 Forecast	494.9	497.9	304.9	4100.72	10049.16	10096.9	1423.0	4727.1	608.2
7	2024	501.0	508.2	313.0	4130.49	10064.04	10661.9	1462.9	4709.8	592.0
8	2025	507.4	518.8	320.6	4151.95	10076.68	11083.0	1703.4	4904.4	575.9
9	2026	512.8	529.9	327.6	4171.19	10083.88	10762.1	1715.3	4683.2	563.9
10	2027	518.9	541.3	335.2	4190.15	10088.31	10783.8	1613.3	4481.0	557.3
11	2028	525.1	552.3	342.6	4208.62	10091.63	10961.9	1644.0	4700.2	551.1
Line No.	Year	Non- Manufacturing Employment (Thousands)	Educ & Health Employment (Thousands)	TTU ¹ Employment (Thousands)	Financial Employment (Thousands)	Information Employment (Thousands)	Professional & Business Service Employment (Thousands)	Government Employment (Thousands)	Other Services Employment (Thousands)	
12	2018	3799.7	685.99	791.59	221.0	56.0	659.4	609.0	166.0	
13	2019	3826.8	690.60	796.72	225.8	55.5	655.7	615.8	167.3	
14	2020	3449.0	636.52	741.66	224.2	50.2	596.4	576.0	142.1	
15	2021	3630.7	652.22	782.76	232.7	52.8	633.2	573.9	155.1	
16	2022	3766.4	662.97	805.95	231.6	56.6	658.5	591.4	162.9	
17	2023 Forecast	3825.2	682.63	811.38	228.8	57.2	664.7	606.5	161.5	
18	2024	3840.8	699.12	797.01	231.0	57.6	672.3	612.9	164.2	
19	2025	3845.5	705.63	779.08	235.3	59.0	675.3	617.5	166.6	
20	2026	3849.4	706.42	770.75	238.4	58.3	677.3	620.7	168.8	
21	2027	3854.8	707.47	765.66	240.8	57.5	682.3	623.0	170.4	
22	2028	3862.3	708.52	757.63	240.1	57.1	697.1	624.1	171.9	

1) Transportation, trade & utilities

Michigan Public Service Commission
DTE Electric Company
Variance of Weather-Normalized
Electric Sales (GWh) and Peak (MW)
2018-2022 Historical

Case No. : U-21534
Exhibit: A-15
Schedule: E5
Witness: M.B. Leuker
Page: 1 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		<u>Service Area Annual Sales - GWh</u>				Peak	Weather
Line						Demand	Normalization
<u>No.</u>	<u>Year</u>	<u>Residential</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Total</u>	<u>(MW)</u>	<u>Period</u>
1	<u>Historical</u>						
2	2018	14,935	11,057	20,856	47,072	11,344	1981-2010
3	2019	14,820	10,877	20,299	46,222	11,145	1981-2010
4	2020	15,947	10,080	17,755	44,003	11,246	1981-2010
5	2021	16,122	10,714	18,390	45,442	11,358	2005-2019
6	2022	15,647	10,791	18,434	45,081	10,959	2006-2020
7	2023 ¹	15,350	10,742	18,430	44,727	10,853	2007-2021
8	<u>Forecast</u>						
9	2018	14,948	11,103	20,476	46,759	11,258	
10	2019	14,910	11,020	20,928	47,081	11,221	
11	2020	14,763	10,803	19,976	45,762	11,114	
12	2021	15,477	10,224	18,406	44,318	10,942	
13	2022	15,768	10,789	18,543	45,306	11,390	
14	2023	15,388	10,670	18,127	44,389	11,038	
15	<u>Absolute Percent Variance</u>						
16	2018	0.09%	0.42%	1.86%	0.67%	0.76%	
17	2019	0.60%	1.30%	3.00%	1.82%	0.67%	
18	2020	8.02%	6.69%	11.12%	3.84%	1.19%	
19	2021	4.17%	4.80%	0.09%	2.54%	3.80%	
20	2022	0.77%	0.03%	0.59%	0.50%	3.78%	
21	2023	0.24%	0.68%	1.67%	0.76%	1.68%	
22	Average 18-22	2.73%	2.65%	3.33%	1.87%	2.04%	
23	Average 18-23 ²	0.43%	0.60%	1.78%	0.94%	1.72%	

¹⁾ 2023 Historical sales are 10 months of actuals and 2 months of forecast

²⁾ Average 18-23 excludes years 2020 & 2021 due to the COVID-19 pandemic

Michigan Public Service Commission
DTE Electric Company
ITRON's Benchmarking Survey Results
2018-2022 Historical

Case No. : U-21534
Exhibit: A-15
Schedule: E5
Witness: M.B. Leuker
Page: 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)
	Absolute Percent Variance					
Line						Peak
No.	Year	Residential	Commercial	Industrial	Total	Demand
1	2018	1.79%	2.00%	1.92%	1.25%	2.13%
2	2019	1.17%	1.65%	4.07%	1.39%	2.38%
3	2020	3.78%	6.53%	8.32%	3.13%	2.76%
4	2021	2.37%	3.09%	3.14%	1.69%	3.14%
5	2022	1.88%	2.74%	3.79%	1.78%	3.06%
6	Average	2.20%	3.20%	4.25%	1.85%	2.69%

DTE Electric Company
Annual Service Area Customer Counts by
Major Customer Classes
2018-2022 Historical 2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E6
Witness: M.B. Leuker
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	(a)	(b)	(c)	(d)	(e)	(f)
	Annual Service Area Customer Counts					
Line No.	Year	Residential	Small C&I	Large C&I	Other	Total
1	2018	1,991,879	204,955	3,162	1,068	2,201,064
2	2019	2,003,542	205,744	3,152	1,057	2,213,495
3	2020	2,019,744	206,954	3,134	1,058	2,230,890
4	2021	2,036,329	208,957	3,117	1,056	2,249,460
5	2022	2,047,607	210,158	3,089	1,049	2,261,903
6	2023	2,055,641	210,910	3,078	1,043	2,270,672
7	2024	2,064,797	211,982	3,075	1,043	2,280,897
8	2025	2,074,827	212,968	3,075	1,043	2,291,913
9	2026	2,084,117	213,840	3,075	1,043	2,302,075
10	2027	2,092,054	214,561	3,075	1,043	2,310,733
11	2028	2,098,709	215,149	3,075	1,043	2,317,976

DTE Electric Company
Annual Bundled Customer Counts by
Major Customer Classes
2018-2022 Historical 2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E6
Witness: M.B. Leuker
Page: 2 of 3

	(a)	(b)	(c)	(d)	(e)	(f)
	Annual Bundled Customer Counts					
Line No.	Year	Residential	Small C&I	Large C&I	Other	Total
1	2018	1,991,840	201,115	2,450	1,068	2,196,473
2	2019	2,003,509	202,014	2,441	1,057	2,209,021
3	2020	2,019,712	203,297	2,434	1,058	2,226,500
4	2021	2,036,306	205,203	2,381	1,056	2,244,946
5	2022	2,047,591	206,429	2,346	1,049	2,257,415
6	2023	2,055,622	207,325	2,351	1,043	2,266,341
7	2024	2,064,797	208,512	2,349	1,043	2,276,701
8	2025	2,074,827	209,586	2,349	1,043	2,287,804
9	2026	2,084,117	210,545	2,349	1,043	2,298,054
10	2027	2,092,054	211,354	2,349	1,043	2,306,800
11	2028	2,098,709	212,028	2,349	1,043	2,314,129

DTE Electric Company
Annual Choice Customer Counts by
Major Customer Classes
2018-2022 Historical 2023-2028 Forecast

Case No. : U-21534
Exhibit: A-15
Schedule: E6
Witness: M.B. Leuker
Page: 3 of 3

	(a)	(b)	(c)	(d)	(e)	(f)
Annual Electric Choice Customer Counts						
Line No.	Year	Residential	Small C&I	Large C&I	Other	Total
1	2018	38	3,840	712	-	4,591
2	2019	32	3,730	711	-	4,474
3	2020	32	3,658	700	-	4,390
4	2021	24	3,755	736	-	4,514
5	2022	16	3,729	743	-	4,487
6	2023	19	3,585	727	-	4,330
7	2024	0	3,470	726	-	4,196
8	2025	0	3,383	726	-	4,108
9	2026	0	3,295	726	-	4,021
10	2027	0	3,208	726	-	3,934
11	2028	0	3,121	726	-	3,846

Production by Class					
Cost of Service Study					
PRODUCTION COSTS					
	(a)	(b)	(c)	(d)	(e)
	Total Electric	Total Residential	Total Commercial Secondary	Total Primary	E-1 St Lgt D9 OPL E-2 Signals
1 Rate Base	8,842,313	4,259,085	2,254,541	2,307,588	21,099
<u>Revenues:</u>					
2 Revenue From Electric Sales	3,064,187	1,357,891	779,751	915,758	10,787
3 D13 Present Revenue	10,496	4,725	2,713	3,020	38
4 Misc Revenue	34,716	26,689	4,932	3,043	52
5 Total Adjusted Revenues	3,109,398	1,389,305	787,396	921,821	10,876
<u>Expenses:</u>					
6 Fuel	914,888	392,003	233,702	284,815	4,367
7 Purchased Power	439,217	176,490	102,359	158,762	1,606
8 O & M Expense	578,201	255,830	148,400	171,635	2,335
9 Depreciation	516,998	252,445	131,617	131,848	1,088
10 Other (Reg Assets, etc)	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-
13 Other Taxes	121,965	58,303	31,118	32,236	309
14 Income Taxes	80,252	37,913	20,907	21,257	175
15 Amortizations	-	-	-	-	-
16 Total Expenses	2,651,521	1,172,985	668,104	800,553	9,879
17 Net Oper Income	457,878	216,321	119,292	121,268	997
18 AFUDC & Other	56,701	27,709	14,434	14,440	118
19 Net Adjustments	866	417	221	226	2
20 Adj Net Oper Income	515,445	244,447	133,947	135,934	1,117
21 Rate of Return	5.83%	5.74%	5.94%	5.89%	5.30%
22 Return @ 5.9231 %	523,739	252,270	133,539	136,681	1,250
23 Income Deficiency	8,294	7,823	(408)	747	132
24 Base Revenue Def / (Sufficiency)	11,194	10,558	(551)	1,008	179
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	137,518	67,215	35,006	35,010	287
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	148,712	77,774	34,456	36,018	465
28 Less: D13 Incremental Revenues	(278)	(125)	(72)	(80)	(1)
29 R10 Tax Gross-Up Adjustment (Prod Only)	(0)	3	2	(5)	0
30 Total Revenue Def/ (Sufficiency)	148,990	77,902	34,529	36,093	466
31 Total Base Revenue Requirement	3,213,177	1,435,793	814,280	951,851	11,253

Production by Class								
Cost of Service Study								
PRODUCTION COSTS								
	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	D-1.11/Other Residential Service	D-1.2 Time Of Use	D-2 Residential Space Ht	Total Residential	D-3/Other General Service	D-3.2 Secondary Schools	D-4 Lg Genl Service	Total Commercial Secondary
1 Rate Base	4,166,763	39,854	52,467	4,259,085	1,811,494	74,516	368,532	2,254,541
<u>Revenues:</u>								
2 Revenue From Electric Sales	1,323,961	14,282	19,648	1,357,891	621,948	26,144	131,658	779,751
3 D13 Present Revenue	4,607	50	68	4,725	2,164	91	458	2,713
4 Misc Revenue	26,110	193	386	26,689	4,279	110	543	4,932
5 Total Adjusted Revenues	1,354,678	14,525	20,102	1,389,305	628,391	26,345	132,660	787,396
<u>Expenses:</u>								
6 Fuel	380,714	4,554	6,736	392,003	185,714	7,864	40,125	233,702
7 Purchased Power	171,890	1,934	2,666	176,490	81,481	3,426	17,452	102,359
8 O & M Expense	249,150	2,805	3,876	255,830	118,133	4,967	25,300	148,400
9 Depreciation	247,149	2,300	2,995	252,445	105,917	4,340	21,360	131,617
10 Other (Reg Assets, etc)	-	-	-	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-	-	-	-
13 Other Taxes	57,019	553	731	58,303	24,981	1,030	5,107	31,118
14 Income Taxes	37,096	355	462	37,913	16,727	704	3,477	20,907
15 Amortizations	-	-	-	-	-	-	-	-
16 Total Expenses	1,143,018	12,501	17,465	1,172,985	532,952	22,330	112,822	668,104
17 Net Oper Income	211,660	2,024	2,637	216,321	95,439	4,015	19,838	119,292
18 AFUDC & Other	27,128	252	328	27,709	11,617	476	2,341	14,434
19 Net Adjustments	408	4	5	417	178	7	36	221
20 Adj Net Oper Income	239,196	2,280	2,970	244,447	107,233	4,498	22,216	133,947
21 Rate of Return	5.74%	5.72%	5.66%	5.74%	5.92%	6.04%	6.03%	5.94%
22 Return @ 5.9231 %	246,802	2,361	3,108	252,270	107,297	4,414	21,829	133,539
23 Income Deficiency	7,605	81	137	7,823	64	(85)	(387)	(408)
24 Base Revenue Def / (Sufficiency)	10,264	109	185	10,558	86	(114)	(523)	(551)
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	65,809	611	795	67,215	28,174	1,154	5,678	35,006
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	76,073	720	981	77,774	28,260	1,040	5,156	34,456
28 Less: D13 Incremental Revenues	(122)	(1)	(2)	(125)	(57)	(2)	(12)	(72)
29 R10 Tax Gross-Up Adjustment (Prod Only)	3	0	0	3	1	0	0	2
30 Total Revenue Def/ (Sufficiency)	76,198	721	983	77,902	28,319	1,042	5,168	34,529
31 Total Base Revenue Requirement	1,400,159	15,004	20,630	1,435,793	650,267	27,186	136,827	814,280

Production by Class						
Cost of Service Study						
PRODUCTION COSTS						
	(n)	(o)	(p)	(q)	(r)	(s)
	D-11/Other Primary	D-6.2 Primary Schools	D-8 Interrupt Supply	R-1.1/R-1.2 Metal Melt Process Heat	R-10 Interrupt Supply	Total Primary
1 Rate Base	2,025,857	157,817	67,904	56,009	0	2,307,588
<u>Revenues:</u>						
2 Revenue From Electric Sales	761,701	50,619	29,445	26,252	47,740	915,758
3 D13 Present Revenue	2,650	176	102	91	-	3,020
4 Misc Revenue	2,668	177	105	93	-	3,043
5 Total Adjusted Revenues	767,020	50,972	29,652	26,436	47,740	921,821
<u>Expenses:</u>						
6 Fuel	240,867	15,775	10,574	9,924	7,674	284,815
7 Purchased Power	103,868	7,090	4,080	3,638	40,085	158,762
8 O & M Expense	150,137	10,272	5,930	5,295	(0)	171,635
9 Depreciation	115,837	9,262	3,736	3,013	-	131,848
10 Other (Reg Assets, etc)	-	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-	-
13 Other Taxes	28,295	2,176	964	802	-	32,236
14 Income Taxes	19,090	954	651	561	-	21,257
15 Amortizations	-	-	-	-	-	-
16 Total Expenses	658,095	45,530	25,936	23,233	47,759	800,553
17 Net Oper Income	108,925	5,443	3,716	3,203	(19)	121,268
18 AFUDC & Other	12,687	1,016	408	329	-	14,440
19 Net Adjustments	199	15	7	5	-	226
20 Adj Net Oper Income	121,810	6,474	4,131	3,538	(19)	135,934
21 Rate of Return	6.01%	4.10%	6.08%	6.32%	-25726827.47%	5.89%
22 Return @ 5.9231 %	119,994	9,348	4,022	3,317	0	136,681
23 Income Deficiency	(1,816)	2,874	(109)	(220)	19	747
24 Base Revenue Def / (Sufficiency)	(2,452)	3,878	(147)	(297)	25	1,008
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	30,760	2,464	989	797	-	35,010
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	28,309	6,342	842	500	25	36,018
28 Less: D13 Incremental Revenues	(70)	(5)	(3)	(2)	-	(80)
29 R10 Tax Gross-Up Adjustment (Prod Only)	2	0	0	0	(7)	(5)
30 Total Revenue Def/ (Sufficiency)	28,381	6,347	845	502	19	36,093
31 Total Base Revenue Requirement	790,081	56,966	30,290	26,754	47,759	951,851

Production by Class				
Cost of Service Study				
PRODUCTION COSTS				
	(t)	(u)	(v)	(w)
	D-9 OPL Residential	D-9 OPL Commercial	E-1 St Lght	E-2 Signals
1 Rate Base	439	1,988	8,962	9,710
<u>Revenues:</u>				
2 Revenue From Electric Sales	257	1,225	5,488	3,817
3 D13 Present Revenue	1	4	19	13
4 Misc Revenue	1	4	33	13
5 Total Adjusted Revenues	259	1,233	5,540	3,843
<u>Expenses:</u>				
6 Fuel	120	544	2,453	1,250
7 Purchased Power	41	187	844	533
8 O & M Expense	60	273	1,229	772
9 Depreciation	21	94	425	548
10 Other (Reg Assets, etc)	-	-	-	-
11 Remove Reg Assets	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-
13 Other Taxes	7	30	135	137
14 Income Taxes	1	16	68	90
15 Amortizations	-	-	-	-
16 Total Expenses	251	1,144	5,154	3,330
17 Net Oper Income	8	89	386	514
18 AFUDC & Other	2	10	46	60
19 Net Adjustments	0	0	1	1
20 Adj Net Oper Income	10	100	433	575
21 Rate of Return	2.34%	5.02%	4.83%	5.92%
22 Return @ 5.9231 %	26	118	531	575
23 Income Deficiency	16	18	98	0
24 Base Revenue Def / (Sufficiency)	21	24	133	1
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	5	25	111	145
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	27	49	244	146
28 Less: D13 Incremental Revenues	(0)	(0)	(1)	(0)
29 R10 Tax Gross-Up Adjustment (Prod Only)	0	0	0	0
30 Total Revenue Def/ (Sufficiency)	27	49	244	146
31 Total Base Revenue Requirement	284	1,274	5,733	3,963

Distribution by Voltage

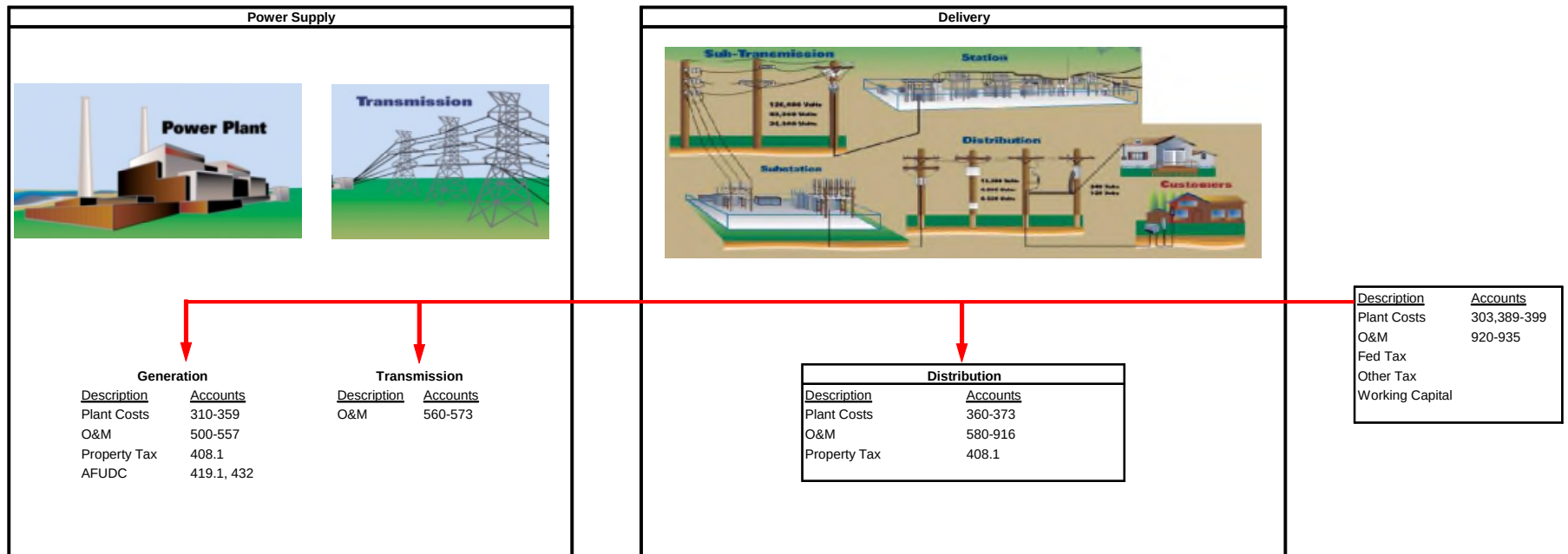
Cost of Service Study

DISTRIBUTION COSTS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Total Electric	Residential Secondary	Commercial Secondary	Primary	Subtransmission	Transmission	D-9 OPL Residential	D-9 OPL Commercial	E-1 St Lght	E-2 Signals
1 Rate Base	13,265,676	8,089,699	3,653,887	1,015,495	83,659	112,062	12,665	32,514	256,153	9,542
<u>Revenues:</u>										
2 Revenue From Electric Sales	2,274,831	1,428,732	593,121	161,015	11,229	11,411	1,850	8,352	57,552	1,571
3 D13 Present Revenue	566	356	148	40	3	3	0	2	14	0
4 Misc Revenue	80,620	59,394	11,045	3,557	2,086	3,664	22	253	573	26
5 Total Adjusted Revenues	2,356,017	1,488,482	604,314	164,611	13,318	15,077	1,872	8,606	58,139	1,597
<u>Expenses:</u>										
6 Fuel	-	-	-	-	-	-	-	-	-	-
7 Purchased Power	-	-	-	-	-	-	-	-	-	-
8 O & M Expense	688,750	474,247	157,239	39,769	2,088	3,483	454	1,564	9,448	458
9 Depreciation	749,247	460,128	202,212	47,223	3,210	3,670	1,444	3,217	27,633	510
10 Other (Reg Assets, etc)	-	-	-	-	-	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-	-	-	-	-	-
13 Other Taxes	259,987	160,058	69,331	19,031	1,563	2,076	345	826	6,578	178
14 Income Taxes	88,937	53,258	23,724	7,919	873	790	(50)	405	1,957	61
15 Amortizations	-	-	-	-	-	-	-	-	-	-
16 Total Expenses	1,786,921	1,147,691	452,506	113,941	7,733	10,020	2,194	6,013	45,617	1,207
17 Net Oper Income	569,097	340,791	151,808	50,670	5,584	5,057	(321)	2,594	12,523	391
18 AFUDC & Other	1,171	714	323	90	7	10	1	3	23	1
19 Net Adjustments	1,388	846	382	106	9	12	1	3	27	1
20 Adj Net Oper Income	571,655	342,352	152,513	50,866	5,601	5,079	(319)	2,600	12,572	393
21 Rate of Return	4.31%	4.23%	4.17%	5.01%	6.69%	4.53%	-2.52%	8.00%	4.91%	4.11%
22 Return @ 5.9231 %	785,739	479,161	216,423	60,149	4,955	6,638	750	1,926	15,172	565
23 Income Deficiency	214,084	136,809	63,911	9,283	(645)	1,559	1,069	(674)	2,600	173
24 Base Revenue Def / (Sufficiency)	288,935	184,643	86,256	12,528	(871)	2,104	1,443	(910)	3,509	233
25 Tree Trim Surge Rev Req (Dist Only)	18,786	12,228	5,664	718	0	1	6	22	132	15
26 Monroe Reg Asset Rev Req (Prod Only)	-	-	-	-	-	-	-	-	-	-
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	307,721	196,870	91,920	13,247	(871)	2,105	1,449	(888)	3,641	248
28 Less: D13 Incremental Revenues	59	37	15	4	0	0	0	0	1	0
29 R10 Tax Gross-Up Adjustment (Prod Only)	-	-	-	-	-	-	-	-	-	-
30 Total Revenue Def/ (Sufficiency)	307,663	196,834	91,905	13,242	(871)	2,105	1,449	(888)	3,640	248
31 Total Base Revenue Requirement	2,582,494	1,625,565	685,026	174,257	10,358	13,515	3,299	7,463	61,191	1,819

Direct Costs

Indirect Costs



Indirect Costs are functionalized based on a combination of direct assignment and labor allocation.

REVENUE

DTE Electric Company
Unbundled Cost of Service
Functionalization and Allocation Overview

Case No.: U-21534
Exhibit: A-16
Schedule: F1.3
Witness: H. J. Maroun
Page: 2 of 28

	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
<u>Revenue</u>					
1	D13 Present Power Supply Revenues	Prod	400a	400a	Production Billed Revenue excl R10
2	D13 Present Distribution Revenues	Dist	401	401	Distribution Billed Revenue
<u>Revenue Credits</u>					
3	Late Payment Penalty	Revenue	400a	401	Production Billed Revenue excl R10
4	Securitization Servicing Fees	Netplt	500	501	Distribution Billed Revenue
5	Returned Checks & Collection	Dist	402	402	Distribution Net Plant
6	Pole Contacts & Rent	Dist	364	364	Total Billed Revenue
7	E1 Antenna Rental Revenue	Dist	DIR	DIR	Poles + Fixtures
7	Industrial Steam	Prod	100	100	Poles + Fixtures
8	Wholesale Delivery Services	Dist	202T	202T	Direct
9	Low Income Discount Direct	Dist	DIR	DIR	Energy @ System Output
10	Low Income Discount Allocated	Dist	800	800	N-coin Pk Subtrans Lns
11	Senior Citizen Discount Direct	Dist	DIR	DIR	Direct
12	Senior Citizen Discount Allocated	Dist	800	800	Distribution Number Of Customers
13	Interdepartmental	Netplt	800	800	Direct
14	R2 Revenue	Dist	DIR	DIR	Distribution Number Of Customers
15	Service Charges	Dist	501	501	Distribution Number Of Customers
16	D9 Commercial Post Charge	Dist	DIR	DIR	Distribution Net Plant
17	Unauthorized Use	Prod	190	190	Direct
18	Other Revenue	Prod	100	100	Direct
<u>D13 Incremental Revenue Credit</u>					
19	D13 Incremental Power Supply Revenues	Prod	400a	400a	.90 Eng .10 4CP Dmd
20	D13 Incremental Distribution Revenues	Dist	401	401	Energy @ System Output
<u>From RETURN Section</u>					
21	Tree Trim Surge Rev Req (Dist Only)	Dist	593	593	364A + 365A + 369A
22	Monroe Reg Asset Rev Req (Prod Only)	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng
23	R10 Tax Gross-Up Adjustment (Prod Only)	Prod	400a	401	Production Billed Revenue excl R10

ADJ1

DTE Electric Company
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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description	
	Func. Factr					
	<u>Adjustments to NOI</u>					
1	Other	Netplt	900a	901	Prod Rate Base excl R10	Dist Rate Base
2	EIS Loss	Netplt	900a	901	Prod Rate Base excl R10	Dist Rate Base
3	FIT Eff Of Allowd Int	Netplt	900a	901	Prod Rate Base excl R10	Dist Rate Base
4	Interest Synch Adj	Netplt	900a	901	Prod Rate Base excl R10	Dist Rate Base

TAX

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
1 Other Tax	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
2 Property Tax - Prod	Prod	520	520	PIS - Prod Direct	PIS - Prod Direct
3 Property Tax - Dist	Dist	521	521	PIS - Dist Direct	PIS - Dist Direct
4 Soc Sec & Unempl -Prod (labor)	Prod	620	620	Prod Labor	Prod Labor
5 Soc Sec & Unempl -Dist (labor)	Dist	621	621	Distribution Labor	Distribution Labor
6 MPSC Assessment Fee	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
7 Sale/Use Tax	Netplt	602a	603	Prod O&M excl Fuel PNI, excl R10	Dist O&M
8 MBT, MI Bus Tx	PreTaxInc	910a	910	Net Income excl R10	Net Income
9 Federal Income Tax	PreTaxInc	910a	910	Net Income excl R10	Net Income

WRKCAPB

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
<u>Assets</u>					
1 Non-Current Portion of Allowances	Netplt	500	501	Production Net Plant	Distribution Net Plant
2 Investment and Special Funds	Netplt	500	501	Production Net Plant	Distribution Net Plant
3 Cash	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
4 Customer Accounts Receivable	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
5 Other Accounts Receivable	Netplt	500	501	Production Net Plant	Distribution Net Plant
6 Uncollectible Reserve	Dist	402	402	Total Billed Revenue	Total Billed Revenue
7 Unbilled Revenues	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
8 Inventories - Fuel	Prod	192	192	Sch 190 Less R10	Sch 190 Less R10
9 Inventories - Material and Supplies	Netplt	600a	601	Prod O&M-Genl-Fuel-Purch Pwr excl R10	Dist O&M-Genl
10 Prepayments	Netplt	600a	601	Prod O&M-Genl-Fuel-Purch Pwr excl R10	Dist O&M-Genl
11 Unamortized Loss on Reacquired Debt	Netplt	500	501	Production Net Plant	Distribution Net Plant
12 Def Debit - Prepaid Pension Asset	Labor	620	621	Prod Labor	Distribution Labor
13 Reg Asset - Pension Deferral	Labor	620	621	Prod Labor	Distribution Labor
14 Reg Asset - Ludington	Prod	256	256	Sch 255 Excl R10	Sch 255 Excl R10
15 Reg Asset - Customer 360	NetPlt	500	501	Production Net Plant	Distribution Net Plant
16 Reg Asset - Residential Income Assistance	Dist	500	501	Production Net Plant	Distribution Net Plant
17 Reg Asset - Program Eval. Review Committee (PERC)	Prod	522	522	PIS - Prod Total	PIS - Prod Total
18 Reg Asset - Advanced Distribution Management System (ADMS)	Dist	500	501	Production Net Plant	Distribution Net Plant
19 Reg Asset - Charging Forward	Revenue	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
20 Reg Asset - Advanced Customer Pricing Pilot Costs	Dist	500	501	Production Net Plant	Distribution Net Plant
21 Reg Asset - Time of Use Deferred Project Costs	Dist	500	501	Production Net Plant	Distribution Net Plant
22 Reg Asset - Demand Response	Prod	520	521	PIS - Prod Direct	PIS - Dist Direct
23 Reg Asset - Incentive Deferral	Netplt	520	521	PIS - Prod Direct	PIS - Dist Direct
24 Reg Asset - Low Income Assistance Tracker	Dist	800	800	Distribution Number Of Customers	Distribution Number Of Customers
25 Reg Asset - Low Income Payment Stability Plan	Dist	800	800	Distribution Number Of Customers	Distribution Number Of Customers
26 Reg Asset - TCJA Under Recovery	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
27 Def Debit - Preliminary Survey and Investigation Charges	Prod	520	521	PIS - Prod Direct	PIS - Dist Direct
28 Def Debit - Prepaid OPEB	Labor	620	621	Prod Labor	Distribution Labor
29 Other Deferred Debits	Netplt	620	621	Prod Labor	Distribution Labor
<u>Liabilities</u>					
30 Accumulated Provision for Injuries and Damages	Labor	620	621	Prod Labor	Distribution Labor
31 Accounts Payable	Netplt	500	501	Production Net Plant	Distribution Net Plant
32 Taxes Payable	Netplt	400a	401	Production Billed Revenue excl R10	Distribution Billed Revenue
33 Interest Payable	Netplt	500	501	Production Net Plant	Distribution Net Plant
34 Other Current Liabilities	Netplt	500	501	Production Net Plant	Distribution Net Plant
35 Regulatory Liab-Other Post Empl Benefits (OPEB)	Labor	620	621	Prod Labor	Distribution Labor
36 Regulatory Liab-OPEB Capitalized	Labor	620	621	Prod Labor	Distribution Labor
37 Regulatory Liab- Pension Capitalized	Labor	620	621	Prod Labor	Distribution Labor
38 Fermi 2 Outage Accrual	Prod	256	256	Sch 255 Excl R10	Sch 255 Excl R10
39 Other Deferred Credits	Netplt	500	501	Production Net Plant	Distribution Net Plant
Total Current Liabilities					
Total Working Capital					

ALWANCE

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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description	
<u>Additions to Rate Base</u>						
1	Capital Lease Property	General	500	501	Production Net Plant	Distribution Net Plant
2	Nuclear Fuel Property	Prod	192	192	Sch 190 Less R10	Sch 190 Less R10
<u>Deductions from Rate Base</u>						
3	Capital Lease Obligations	General	500	501	Production Net Plant	Distribution Net Plant
From RATEBASE1 Section						
<u>Future Use</u>						
4	Distribution	Dist	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
5	Intangible	Intan Plant	520	521	PIS - Prod Direct	PIS - Dist Direct

PIS1

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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
	Production				
1	Production Joint Use	Prod	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng
	Subtransmission				
	<u>350A Land</u>				
2	Subtransmission	Dist	201	Max Dmd;Trans Station	Max Dmd;Trans Station
	<u>350B Land Rights</u>				
3	Subtransmission	Dist	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
	<u>352A Improvements to Land</u>				
4	Subtransmission	Dist	201	Max Dmd;Trans Station	Max Dmd;Trans Station
	<u>352B Buildings</u>				
5	Subtransmission	Dist	201	Max Dmd;Trans Station	Max Dmd;Trans Station
	<u>353A Station Eq.</u>				
6	Subtransmission	Dist	201	Max Dmd;Trans Station	Max Dmd;Trans Station

PIS2

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Subtransmission (cont.)						
<u>355A Poles/Twrs</u>						
1	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>356A OH Conductors</u>						
2	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>357A U G Conduit</u>						
3	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>358A UG Conductors</u>						
4	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns

PIS3

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution						
<u>360A Land & Rights</u>						
1	Joint Use	Dist	203C	203C	Max Inpt Sbstrn Pri Bus Combined	Max Inpt Sbstrn Pri Bus Combined
<u>361A Improvements</u>						
2	Direct	Dist	203B	203B	Max Inpt Sbstrn Pri Bus (T&S Cust)	Max Inpt Sbstrn Pri Bus (T&S Cust)
3	Joint Use	Dist	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>362A Station Equipment</u>						
4	Direct	Dist	203B	203B	Max Inpt Sbstrn Pri Bus (T&S Cust)	Max Inpt Sbstrn Pri Bus (T&S Cust)
5	Joint Use	Dist	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>363 Storage Batteries</u>						
6	Joint Use	Dist	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>364A Poles & Fixtures</u>						
7	Direct	Dist	DIR	DIR	Direct	Direct
8	1 Ph Primary	Dist	215	215	Sch 205 Less St Ltg	Sch 205 Less St Ltg
9	3 Ph Primary	Dist	214	214	Sch 204 Less St Ltg	Sch 204 Less St Ltg
10	Secondary	Dist	215	215	Sch 205 Less St Ltg	Sch 205 Less St Ltg
<u>365A O H Conductors</u>						
11	1 Ph Primary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
12	3 Ph Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
13	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D

PIS4

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution (cont.)						
366A UG Conduit						
1	3 Ph Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
2	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
367A UG Conductors						
3	3 Ph Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
4	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
5	368A Line Transformers	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
6	369A Overhead Svcs	Dist	Dir	Dir	Direct	Direct
7	369B Underground Svcs	Dist	Dir	Dir	Direct	Direct
8	370 All Meters	Dist	370C	370C	Combined Meters	Combined Meters
9	371A Instl Cust Premis	Dist	Dir	Dir	Direct	Direct
10	371B OPL	Dist	371B	371B	OPL OH	OPL OH
11	373.01 O H Street Ltg	Dist	DIR	DIR	Direct	Direct
12	373.02 U G Street Ltg	Dist	DIR	DIR	Direct	Direct
13	373.03-.08 Street Ltg Lum / Wires	Dist	DIR	DIR	Direct	Direct
General & Intangible						
14	Intangible Plant	Intan Plant	520	521	PIS - Prod Direct	PIS - Dist Direct
15	General Plant	General	520	521	PIS - Prod Direct	PIS - Dist Direct
16	MERC	Prod	192	192	Sch 190 Less R10	Sch 190 Less R10

DEPRES1

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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description	
Func. Factr						
Production						
1	Production Joint Use	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng
Subtransmission						
352A Improvements						
2	Subtransmission	Dist	201	201	Max Dmd;Trans Station	Max Dmd;Trans Station
353A Station Eq.						
3	Subtransmission	Dist	201	201	Max Dmd;Trans Station	Max Dmd;Trans Station

DEPRES2

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Subtransmission (cont.)						
<u>355A Poles/Twrs</u>						
1	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>356A OH Conductors</u>						
2	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>357A UG Conduit</u>						
3	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>358A UG Conductors</u>						
4	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns

DEPRES3

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution					
<u>361A Improvements</u>					
1	Direct	203B	203B	Max Inpt Sbstrn Pri Bus (T&S Cust)	Max Inpt Sbstrn Pri Bus (T&S Cust)
2	Joint Use	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>362A Station Equipment</u>					
3	Direct	203B	203B	Max Inpt Sbstrn Pri Bus (T&S Cust)	Max Inpt Sbstrn Pri Bus (T&S Cust)
4	Joint Use	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>363 Storage Batteries</u>					
5	Joint Use	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>364A Poles & Fixtures</u>					
6	Direct	DIR	DIR	Direct	Direct
7	1 Ph Primary	215	215	Sch 205 Less St Ltg	Sch 205 Less St Ltg
8	3 Ph Primary	214	214	Sch 204 Less St Ltg	Sch 204 Less St Ltg
9	Secondary	215	215	Sch 205 Less St Ltg	Sch 205 Less St Ltg
<u>365A OH Conductors</u>					
10	Direct				
11	1 Ph Primary	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
12	3 Ph Primary	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
13	Secondary	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D

DEPRES4

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution (cont.)						
366A U G Conduit						
1	3 Ph Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
2	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
367A UG Conductors						
3	3 PH Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
4	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
5	368 Line Transformers	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
6	369A Overhead Services	Dist	Dir	Dir	Direct	Direct
7	369B UG Services	Dist	Dir	Dir	Direct	Direct
8	370 All Meters	Dist	370C	370C	Combined Meters	Combined Meters
9	371A Instl Cust Premis	Dist	371A	371A	Inst on Customer Premises	Inst on Customer Premises
10	371B OPL	Dist	371B	371B	OPL OH	OPL OH
11	373.01 O H Street Ltg	Dist	DIR	DIR	Direct	Direct
12	373.02 U G Street Ltg	Dist	DIR	DIR	Direct	Direct
13	373.03-.08 Street Ltg Lum / Wires	Dist	DIR	DIR	Direct	Direct
General & Intangible						
14	Intangible Plant	Intan Plant	520	521	PIS - Prod Direct	PIS - Dist Direct
15	General Plant	General	520	521	PIS - Prod Direct	PIS - Dist Direct
16	MERC	Prod	192	192	Sch 190 Less R10	Sch 190 Less R10

CWIP1

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Production						
1	Joint Use	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng
Subtransmission						
<u>352A Improvements</u>						
2	Subtransmission	Dist	201	201	Max Dmd;Trans Station	Max Dmd;Trans Station
<u>353A Station Equipment</u>						
3	Subtransmission	Dist	201	201	Max Dmd;Trans Station	Max Dmd;Trans Station

CWIP2

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Subtransmission (cont.)					
<u>355A Poles, Twrs & Extrs</u>					
1	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns
<u>356A O H Conductors</u>					
2	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns
<u>357A U G Conduit</u>					
3	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns
<u>358A U G Conductors</u>					
4	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns

CWIP3

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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution					
<u>361A Improvements</u>					
1	Joint Use	Dist	203C	203C	Max Inpt Sbstrn Pri Bus Combined
Total 361A					
<u>362A Station Equipment</u>					
2	Joint Use	Dist	203C	203C	Max Inpt Sbstrn Pri Bus Combined
<u>363 Storage Batteries</u>					
3	Joint Use	Dist	203C	203C	Max Inpt Sbstrn Pri Bus Combined
<u>364A Poles & Fixtures</u>					
4	Direct	Dist	DIR	DIR	Direct
5	1 PH Primary	Dist	215	215	Sch 205 Less St Ltg
6	3 PH Primary	Dist	214	214	Sch 204 Less St Ltg
7	Secondary	Dist	215	215	Sch 205 Less St Ltg
<u>365A O H Conductors</u>					
8	1 PH Primary	Dist	205	205	N-coin Pk Outpt Pri D
9	3 PH Primary	Dist	204	204	Max Dmd Inpt Line Xfmr
10	Secondary	Dist	205	205	N-coin Pk Outpt Pri D

CWIP4

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution (cont.)						
366A U G Conduit						
1	3 PH Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
2	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
367A U G Conductors						
3	3 PH Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
4	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
5	368A Line Transformers	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
6	369A Overhead Services	Dist	369A	369A	Services OH	Services OH
7	369B Underground Svcs	Dist	369B	369B	Services UG	Services UG
8	370 All Meters	Dist	370C	370C	Combined Meters	Combined Meters
9	371B OPL	Dist	371B	371B	OPL OH	OPL OH
10	373.01 O H Street Ltg	Dist	DIR	DIR	Direct	Direct
11	373.02 U G Street Ltg	Dist	DIR	DIR	Direct	Direct
12	373.03-.08 Street Ltg Lum / Wires	Dist	DIR	DIR	Direct	Direct
General & Intangible						
13	Intangible Plant	Intan CWIP	520	521	PIS - Prod Direct	PIS - Dist Direct
14	General Plant	General	520	521	PIS - Prod Direct	PIS - Dist Direct
15	MERC	Prod	192	192	Sch 190 Less R10	Sch 190 Less R10
16	AFUDC	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng

DEPEXP1

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Production						
1	Joint Use	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng
Subtransmission						
<u>352A Improvements</u>						
2	Subtransmission	Dist	201	201	Max Dmd;Trans Station	Max Dmd;Trans Station
<u>353A Station Eq.</u>						
3	Subtransmission	Dist	201	201	Max Dmd;Trans Station	Max Dmd;Trans Station

DEPEXP2

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Subtransmission (cont.)						
<u>355A Poles,Twrs</u>						
1	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>356A OH Conductors</u>						
2	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>357A U G Conduit</u>						
3	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns
<u>358A UG Conductors</u>						
4	Subtransmission	Dist	202T	202T	N-coin Pk Subtrans Lns	N-coin Pk Subtrans Lns

DEPEXP3

DTE Electric Company
 Unbundled Cost of Service
 Functionalization and Allocation Overview

Case No.: U-21534
 Exhibit: A-16
 Schedule: F1.3
 Witness: H. J. Maroun
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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution					
<u>361A Improvements</u>					
1	Direct	203B	203B	Max Inpt Sbstrn Pri Bus (T&S Cust)	Max Inpt Sbstrn Pri Bus (T&S Cust)
2	Joint Use	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>362A Station Equipment</u>					
3	Direct	203B	203B	Max Inpt Sbstrn Pri Bus (T&S Cust)	Max Inpt Sbstrn Pri Bus (T&S Cust)
4	Joint Use	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>363 Storage Batteries</u>					
5	Joint Use	203A	203A	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)	Max Inpt Sbstrn Pri Bus (Pri Sec Cust)
<u>364A Poles & Fixtures</u>					
6	Direct	DIR	DIR	Direct	Direct
7	1 Ph Primary	215	215	Sch 205 Less St Ltg	Sch 205 Less St Ltg
8	3 Ph Primary	214	214	Sch 204 Less St Ltg	Sch 204 Less St Ltg
9	Secondary	215	215	Sch 205 Less St Ltg	Sch 205 Less St Ltg
<u>365A O H Conductors</u>					
10	1 Ph Primary	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
11	3 Ph Primary	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
12	Secondary	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D

DEPEXP4

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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
Distribution (cont.)						
<u>366A U G Conduit</u>						
1	3 Ph Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
2	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
<u>367A U G Conductors</u>						
3	3 PH Primary	Dist	204	204	Max Dmd Inpt Line Xfmr	Max Dmd Inpt Line Xfmr
4	Secondary	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
5	368A Line Transformers	Dist	205	205	N-coin Pk Outpt Pri D	N-coin Pk Outpt Pri D
6	369A Overhead Service	Dist	Dir	Dir	Direct	Direct
7	369B Undergrmd Service	Dist	Dir	Dir	Direct	Direct
8	370 All Meters	Dist	370C	370C	Combined Meters	Combined Meters
9	371A Instl Cust Premis	Dist	820	820	Sch 800 Primary,Comm Secondary	Sch 800 Primary,Comm Secondary
10	371B OPL	Dist	371B	371B	OPL OH	OPL OH
11	373.01 O H Street Ltg	Dist	DIR	DIR	Direct	Direct
12	373.02 U G Street Ltg	Dist	DIR	DIR	Direct	Direct
13	373.03-.08 Street Ltg Lum / Wires	Dist	DIR	DIR	Direct	Direct
<u>General & Intangible</u>						
14	Intangible Plant	Intang Plant	520	521	PIS - Prod Direct	PIS - Dist Direct
15	General Plant	General	520	521	PIS - Prod Direct	PIS - Dist Direct
16	MERC Depreciation Expense	Prod	192	192	Sch 190 Less R10	Sch 190 Less R10
17	Amort. of Utility Plant Acq. Adjustment (406)	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng
18	Amort of Pension Reg Asset	Labor	620	621	Prod Labor	Distribution Labor
19	Amort of OPEB Reg Liab	Labor	620	621	Prod Labor	Distribution Labor
20	Amort of Demand Response (407.3)	Intang Plant	520	521	PIS - Prod Direct	PIS - Dist Direct
21	Regulatory Debit - Monroe (407.3)	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng
21	Amort COLA (Fermi)	Prod	255	255	Sch 250 Adj For 75 Dmd 25 Toteng	Sch 250 Adj For 75 Dmd 25 Toteng

OMPRTOT1

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		Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
	<u>Fuel and Purchased Power</u>				
1	501 Fossil	Prod	192	Sch 190 Less R10	Sch 190 Less R10
2	501 Fuel Handling	Prod	192	Sch 190 Less R10	Sch 190 Less R10
3	518 Nuclear	Prod	192	Sch 190 Less R10	Sch 190 Less R10
4	547 Peakers	Prod	192	Sch 190 Less R10	Sch 190 Less R10
5	PNI Direct	Prod	Dir		
6	555 PNI Energy	Prod	111	Sch 100 Less R10	Sch 100 Less R10
7	555 PNI Demand	Prod	251	Sch 200B 4 CP excl R10	Sch 200B 4 CP excl R10
	<u>Fossil Plant Oper Total</u>				
8	500 Supv and Eng'g	Prod	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
9	502 Steam Expenses	Prod	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
10	505 Electric Expenses	Prod	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
11	506 Miscellaneous	Prod	160	.6 Eng .4 4CP Dmd	.6 Eng .4 4CP Dmd
12	509 Allowances	Prod	160	.6 Eng .4 4CP Dmd	.6 Eng .4 4CP Dmd
	<u>Nuclear Plant Oper Total</u>				
13	517 Supv and Eng'g	Prod	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
14	519 Coolants and Watr	Prod	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
15	520 Steam Expenses	Prod	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
16	523 Electric Expenses	Prod	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
17	524 Miscellaneous	Prod	160	.6 Eng .4 4CP Dmd	.6 Eng .4 4CP Dmd
	<u>Hydro Oper Total</u>				
18	535 Supv and Eng'g	Prod	257	Sch 200A 12CP excl R10	Sch 200A 12CP excl R10
19	537 Hydraulic Expense	Prod	257	Sch 200A 12CP excl R10	Sch 200A 12CP excl R10
20	538 Electric Expense	Prod	257	Sch 200A 12CP excl R10	Sch 200A 12CP excl R10
21	539 Miscellaneous	Prod	257	Sch 200A 12CP excl R10	Sch 200A 12CP excl R10

OMPRTOT2

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 Unbundled Cost of Service
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		Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
		<u>Peaker Operation Total</u>				
1	546 Supv and Eng'g	Prod	170	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
2	548 Peeper Expense	Prod	180	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
3	549 Miscellaneous	Prod	160	160	.6 Eng .4 4CP Dmd	.6 Eng .4 4CP Dmd
		<u>Other Power Supply Expense</u>				
4	556 Sys Cntl Load Disp	Prod	188	188	.88 Eng .12 4CP Dmd	.88 Eng .12 4CP Dmd

OMPRTOT3

DTE Electric Company
Unbundled Cost of Service
Functionalization and Allocation Overview

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
<u>Fossil Maintenance</u>					
1	510 Supv and Eng'g	Prod 170	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
2	511 Structures	Prod 120	120	.2 Eng .8 4CP Dmd	.2 Eng .8 4CP Dmd
3	512 Steam Expenses	Prod 180	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
4	513 Electric	Prod 185	185	.85 Eng .15 4CP Dmd	.85 Eng .15 4CP Dmd
5	514 Miscellaneous	Prod 150	150	.5 Eng .5 4CP Dmd	.5 Eng .5 4CP Dmd
<u>Nuclear Plant Maint</u>					
6	528 Supv and Eng'g	Prod 170	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
7	529 Structures	Prod 120	120	.2 Eng .8 4CP Dmd	.2 Eng .8 4CP Dmd
8	530 Reactor	Prod 180	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
9	531 Electric	Prod 185	185	.85 Eng .15 4CP Dmd	.85 Eng .15 4CP Dmd
10	532 Miscellaneous	Prod 150	150	.5 Eng .5 4CP Dmd	.5 Eng .5 4CP Dmd
<u>Hydro Maint</u>					
11	541 Supv and Eng'g	Prod 170	170	.7 Eng .3 4CP Dmd	.7 Eng .3 4CP Dmd
12	542 Structures	Prod 120	120	.2 Eng .8 4CP Dmd	.2 Eng .8 4CP Dmd
13	543 Hydraulic	Prod 180	180	.8 Eng .2 4CP Dmd	.8 Eng .2 4CP Dmd
14	544 Electric	Prod 185	185	.85 Eng .15 4CP Dmd	.85 Eng .15 4CP Dmd
15	545 Miscellaneous	Prod 150	150	.5 Eng .5 4CP Dmd	.5 Eng .5 4CP Dmd
<u>Peaker Maintenance</u>					
16	552 Structures	Prod 120	120	.2 Eng .8 4CP Dmd	.2 Eng .8 4CP Dmd
17	553 Equipment	Prod 185	185	.85 Eng .15 4CP Dmd	.85 Eng .15 4CP Dmd
18	554 Miscellaneous	Prod 150	150	.5 Eng .5 4CP Dmd	.5 Eng .5 4CP Dmd

OMTOTAL2

DTE Electric Company
Unbundled Cost of Service
Functionalization and Allocation Overview

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
<u>Transmission Operation</u>					
1	(561.4) Sched, Sys Ctrl and Dispatch Svcs	Prod	192	192	Sch 190 Less R10
2	562 Station Equipment	Dist	562	562	353A
3	565 Trans By Others Direct	Prod	Dir	Dir	Direct
4	565 Trans By Others (ERES)	Prod	257	257	Sch 200A 12CP excl R10
<u>Regional Market Expense</u>					
5	575.7 Mkt Facilitation, Monit and Compl Svcs	Prod	192	192	Sch 190 Less R10

OMTOTAL3

DTE Electric Company
 Unbundled Cost of Service
 Functionalization and Allocation Overview

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
<u>Distribution Operation</u>					
1	580 Supv & Engineering	Dist	580	580	Sum 581-589 Labor (Dist Ops)
2	581 Load Dispatch	Dist	581	581	362A + 365A + 367A&B
3	582 Station Expense	Dist	582	582	362A
4	583 Overhead Expense	Dist	583	583	364A + 365A + 368A
5	584 Underground Exp	Dist	584	584	366A + 367AB + 368BC
6	586 Meter Expense	Dist	370C	370C	Meters Combined
7	587 Cust Instl Expense	Dist	370C	370C	Meters Combined
8	588 Miscellaneous	Dist	521	521	PIS - Dist Direct
<u>Distribution Maintenance</u>					
9	590 Supv & Engineering	Dist	590	590	Sum 591-598 Labor (Dist Maint)
10	591 Structures	Dist	591	591	361 A & B
11	592 Station Equipment	Dist	203C	203C	Max Inpt Sbstrn Pri Bus Combined
12	593 Overhead Lines	Dist	593	593	364A + 365A + 369A
13	594 Underground Lines	Dist	594	594	366A + 367AB + 369B
14	596 St Lts & OPL	Dist	DIR	DIR	Direct

OMTTOTAL4

DTE Electric Company
 Unbundled Cost of Service
 Functionalization and Allocation Overview

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	Func. Factr	Prod Alloc	Dist Alloc	Prod Alloc Description	Dist Alloc Description
<u>Customer Accounts Expense</u>					
1	901 Supervision	Dist	805	805	902 & 903 Labor (Meter rd, Cust Rec)
2	902 Meter Reading	Dist	370C	370C	Meters Combined
3	903 Rcrds & Collection	Dist	800	800	Distribution Number Of Customers
4	903 Rcrds & Collection Merch Fees-Res	Dist	DIR	DIR	Direct
5	903 Rcrds & Collection Merch Fees-Comm	Dist	DIR	DIR	Direct
6	904 Uncollectibles	Dist	402	402	Total Billed Revenue
7	905 Misc Expenses	Dist	806	806	902 & 903 Total (Meter rd, Cust Rec)
<u>Customer Services</u>					
8	907 Supervision	Dist	800	800	Distribution Number Of Customers
9	908 Customer Assist	Dist	800	800	Distribution Number Of Customers
10	909 Info & Inst	Dist	800	800	Distribution Number Of Customers
11	910 Miscellaneous	Dist	800	800	Distribution Number Of Customers
<u>Sales Expense</u>					
12	911 Supervision	Dist	521	521	PIS - Dist Direct
13	912 Demo & Selling	Dist	521	521	PIS - Dist Direct
<u>Administrative & General</u>					
14	A&G	Labor	620	621	Prod Labor
					Distribution Labor

DTE Electric Company
Customer Charges by Voltage Class
(thousands of dollars)

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Account	Residential	Commercial Secondary	Primary	Sub-Trans	Transmission	Total
1	Dist Operation Exp:						
2	586 Meters	\$ 7,752	\$ 1,194	\$ 110	\$ 7	\$ 5	\$ 9,068
3	587 Customer Installs	394	61	6	0	0	460
4	Dist Maintenance Exp:						
5	597 Meters	-	-	-	-	-	-
6							
7	Customer Accounts						
8	901 Supervision	2,024	209	3	0	0	2,237
9	902 Meter Read	1,916	295	27	2	1	2,241
10	903 Customer Records	84,436	11,236	106	3	3	95,784
11	905 Miscellaneous	0	0	0	0	0	0
12							
13	Cust Serv & Inf						
14	907 Supervision	3,752	385	5	0	0	4,142
15	908 Customer Assist	14,847	1,524	21	1	0	16,393
16	909 Info & Instr	(3)	(0)	(0)	(0)	(0)	(3)
17	910 Miscellaneous	5,544	569	8	0	0	6,122
18							
19	Depreciation Expense						
20	369 Services Depreciation Expense	33,213	4,648	467	102	269	38,699
21	370 Meters Depreciation Expense	25,080	3,862	356	22	17	29,338
22							
23	Return on Meters and Services in Rate Base						
24	Plant						
25	369 Services	\$ 520,847	\$ 72,607	\$ 7,089	\$ 1,552	\$ 4,082	\$ 606,177
26	370 Meters	487,907	75,139	6,921	432	337	570,737
27	CWIP						
28	369 Services	(12,132)	(1,528)	(27)	(6)	(15)	(13,708)
29	370 Meters	5,640	869	80	5	4	6,597
30	Reserve						
31	369 Services	357,937	50,219	5,145	1,127	2,962	417,390
32	370 Meters	<u>116,441</u>	<u>17,932</u>	<u>1,652</u>	<u>103</u>	<u>80</u>	<u>136,208</u>
33							
34	Rate base	<u>\$ 527,884</u>	<u>\$ 78,936</u>	<u>\$ 7,267</u>	<u>\$ 754</u>	<u>\$ 1,364</u>	<u>\$ 616,205</u>
35							
36	Weighted average cost of capital (WACC)	5.92%	5.92%	5.92%	5.92%	5.92%	5.92%
37							
38	Return (Line 34 * Line 36)	\$ 31,267	\$ 4,675	\$ 430	\$ 45	\$ 81	\$ 36,498
39							
40	Property Tax						
41	Property Tax on meters and services	<u>\$ 12,670</u>	<u>\$ 5,695</u>	<u>\$ 1,574</u>	<u>\$ 129</u>	<u>\$ 170</u>	<u>20,237</u>
42							
43	Total Customer Related Cost	<u>\$ 222,892</u>	<u>\$ 34,353</u>	<u>\$ 3,113</u>	<u>\$ 312</u>	<u>\$ 547</u>	<u>\$ 261,216</u>
44							
45	Customers	2,074,827	212,968	2,909	93	70	2,290,867
46	Cost per Customer per Year	107.43	161.31	1,070.10	3,354.12	7,862.97	
47							
48	Cost per Customer per Month	<u>\$ 8.95</u>	<u>\$ 13.44</u>	<u>\$ 89.18</u>	<u>\$ 279.51</u>	<u>\$ 655.25</u>	

CAPACITY CHARGE						
Cost of Service Study						
75-0-25						
PRODUCTION COSTS						
	(a)	(b)	(c)	(d)	(e)	
	Total Electric	Total Residential	Total Commercial Secondary	Total Primary	E-1 St Lgt D9 OPL E-2 Signals	
CAPACITY COSTS DETERMINATION						
1	Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 31)					
	~~Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 29)~~					
2	\$	3,213,177				
		(914,888)				
3						
		(6,463)				
4						
		(40,376)				
5						
		(260,787)				
6						
		(33,569)				
7						
	\$	1,957,094				
8						
9						
		(983,347)				
10						
11						
	\$	973,747				
12						
13						
		12,277 MW				
14						
15						
		79,315				
16						
17						
		217.30				
18						
19	Allocator					
20		100.0000	51.7411	25.3267	22.8438	0.0884
21						
22	Revenue Requirement					
23	Capacity Revenue Requirement (Line 11 * Line 20/100)					
	~~Capacity Revenue Requirement (Line 8 * Line 9/100)~~					
	\$	973,747	\$ 503,827	\$ 246,618	\$ 222,441	\$ 860
24	Non-Capacity Revenue Requirement (Line 25 less Line 23)					
	~~Non-Capacity Revenue Requirement (Line 12 less Line 10)~~					
		2,239,430	931,965	567,662	729,410	10,393
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 Line 31)					
	~~Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)~~					
	\$	3,213,177	\$ 1,435,793	\$ 814,280	\$ 951,851	\$ 11,253

DTE Electric Company
Capacity Charge Revenue Requirement by Customer Class /
SRM Capacity Charge
(thousands of dollars)

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[illegible]

		CAPACITY CHARGE					
		<u>Cost of Service Study</u>					
		75-0-25					
		PRODUCTION COSTS					
		(k)	(l)	(m)	(n)	(o)	(p)
		D-11/Other Primary	D-6.2 Primary Schools	D-8 Interrupt Supply	R-1.1/R-1.2 Metal Melt Process Heat	R-10 Interrupt Supply	Total Primary
		<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>

	Allocator						
20	Sch 200B 4 CP Excl R10 (Alloc. 251)	-	-	-			0.0884
	Revenue Requirement						
23	Capacity Revenue Requirement (Line 11 * Line 20/100) ~~Capacity Revenue Requirement (Line 8 * Line 9/100)~~	\$ -	\$ -	\$ -			\$ 860
24	Non-Capacity Revenue Requirement (Line 25 less Line 23) ~~Non-Capacity Revenue Requirement (Line 12 less Line 10)~~	<u>284</u>	<u>1,274</u>	<u>5,733</u>			<u>3,103</u>
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 Line 31) ~~Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)~~	\$ 284	\$ 1,274	\$ 5,733	\$		3,963

	(a)	(b)	(c)
	Total O&M	Labor O&M	Variable O&M (a)-(b)
POWER PRODUCTION EXPENSES			
1 501 Fuel Handling 1/	\$ 27,758	\$ -	\$ 27,758
2 502 Steam Expenses 2/	15,236	15,792	\$ -
3 505 Electric Expenses 2/	2,179	3,238	\$ -
4 519 Coolants and Water	2,559	2,251	\$ 308
5 520 Steam Expenses	(11,294)	4,299	\$ -
6 538 Electric Expense	1,116	-	\$ 1,116
7 548 Peaker Expense	4,405	17	4,388
8 TOTAL	\$ 41,959	\$ 25,597	\$ 33,569

1/ Labor O&M deduction in 501 Fuel Handling eliminated per U-20836 Order
2/ Normalized to eliminate negative variable O&M

(a)		
	Source	Amount
MERC		
1	Gross Plant in Service	WP A16 F1 Sch 5 \$ 101,319
2	Less: Accumulated Depreciation	WP A16 F1 Sch 6 (77,907)
3	CWIP	WP A16 F1 Sch 8 156
4	Net Plant	Sum Lines 1 - 3 23,569
5	Weighted Average Cost of Capital	Exh A-14 Sch D1 5.92%
6	Return	Line 4 x Line 5 \$ 1,396
7	Depreciation Expense	WP A16 F1 Sch 7 4,092
8	Property Tax	WP A16 F1 Sch 17 975
9	MERC Revenue Requirement	Sum Lines 6 - 8 \$ 6,463

Production by Class

Alternate Cost of Service Study

PRODUCTION COSTS

	(a)	(b)	(c)	(d)	(e)
	Total Electric	Total Residential	Total Commercial Secondary	Total Primary	E-1 St Lgt D9 OPL E-2 Signals
1 Rate Base	8,842,313	4,259,245	2,254,311	2,307,658	21,099
<u>Revenues:</u>					
2 Revenue From Electric Sales	3,064,187	1,357,891	779,751	915,758	10,787
3 D13 Present Revenue	10,496	4,725	2,713	3,020	38
4 Misc Revenue	34,716	26,689	4,932	3,043	52
5 Total Adjusted Revenues	3,109,398	1,389,305	787,396	921,821	10,876
<u>Expenses:</u>					
6 Fuel	914,888	392,002	233,705	284,814	4,367
7 Purchased Power	439,217	176,494	102,354	158,764	1,606
8 O & M Expense	578,201	255,836	148,393	171,637	2,335
9 Depreciation	516,998	252,455	131,602	131,853	1,088
10 Other (Reg Assets, etc)	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-
13 Other Taxes	121,965	58,305	31,115	32,237	309
14 Income Taxes	80,252	37,910	20,912	21,256	175
15 Amortizations	-	-	-	-	-
16 Total Expenses	2,651,521	1,173,002	668,079	800,560	9,879
17 Net Oper Income	457,878	216,304	119,316	121,261	997
18 AFUDC & Other	56,701	27,710	14,432	14,440	118
19 Net Adjustments	866	417	221	226	2
20 Adj Net Oper Income	515,445	244,431	133,969	135,927	1,117
21 Rate of Return	5.83%	5.74%	5.94%	5.89%	5.30%
22 Return @ 5.9231 %	523,739	252,279	133,525	136,685	1,250
23 Income Deficiency	8,294	7,849	(444)	757	132
24 Base Revenue Def / (Sufficiency)	11,194	10,593	(600)	1,022	179
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	137,518	67,218	35,002	35,011	287
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	148,712	77,811	34,402	36,034	465
28 Less: D13 Incremental Revenues	(278)	(125)	(72)	(80)	(1)
29 R10 Tax Gross-Up Adjustment (Prod Only)	(0)	3	2	(5)	0
30 Total Revenue Def/ (Sufficiency)	148,990	77,939	34,476	36,109	466
31 Total Base Revenue Requirement	3,213,177	1,435,830	814,227	951,867	11,253

Production by Class

Alternate Cost of Service Study

PRODUCTION COSTS

	(f)	(g)	(h)	(i)	(j)	(j ev)	(k)	(l)	(m)
	D-1.11/Other Residential Service	D-1.2 Time Of Use	D-2 Residential Space Ht	Total Residential	D-3/Other General Service	D3.11 EV with DCFC	D-3.2 Secondary Schools	D-4 Lg Genl Service	Total Commercial Secondary
1 Rate Base	4,166,920	39,856	52,469	4,259,245	1,808,083	3,165	74,518	368,544	2,254,311
Revenues:									
2 Revenue From Electric Sales	1,323,961	14,282	19,648	1,357,891	620,914	1,034	26,144	131,658	779,751
3 D13 Present Revenue	4,607	50	68	4,725	2,161	4	91	458	2,713
4 Misc Revenue	26,110	193	386	26,689	4,275	4	110	543	4,932
5 Total Adjusted Revenues	1,354,678	14,525	20,102	1,389,305	627,349	1,042	26,345	132,660	787,396
Expenses:									
6 Fuel	380,712	4,554	6,735	392,002	185,357	359	7,864	40,125	233,705
7 Purchased Power	171,894	1,934	2,666	176,494	81,326	149	3,426	17,452	102,354
8 O & M Expense	249,155	2,805	3,876	255,836	117,908	217	4,967	25,301	148,393
9 Depreciation	247,160	2,300	2,995	252,455	105,717	184	4,340	21,361	131,602
10 Other (Reg Assets, etc)	-	-	-	-	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-	-	-	-	-
13 Other Taxes	57,021	553	731	58,305	24,934	44	1,030	5,108	31,115
14 Income Taxes	37,093	355	462	37,910	16,718	13	704	3,477	20,912
15 Amortizations	-	-	-	-	-	-	-	-	-
16 Total Expenses	1,143,035	12,501	17,465	1,173,002	531,960	967	22,330	112,823	668,079
17 Net Oper Income	211,643	2,024	2,637	216,304	95,389	75	4,015	19,837	119,316
18 AFUDC & Other	27,130	252	328	27,710	11,595	20	476	2,342	14,432
19 Net Adjustments	408	4	5	417	177	0	7	36	221
20 Adj Net Oper Income	239,181	2,280	2,970	244,431	107,161	96	4,498	22,214	133,969
21 Rate of Return	5.74%	5.72%	5.66%	5.74%	5.93%	3.02%	6.04%	6.03%	5.94%
22 Return @ 5.9231 %	246,811	2,361	3,108	252,279	107,095	187	4,414	21,829	133,525
23 Income Deficiency	7,630	81	138	7,849	(67)	92	(84)	(385)	(444)
24 Base Revenue Def / (Sufficiency)	10,298	109	186	10,593	(90)	124	(114)	(520)	(600)
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-	-	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	65,811	611	795	67,218	28,121	49	1,154	5,678	35,002
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	76,109	720	981	77,811	28,031	173	1,040	5,158	34,402
28 Less: D13 Incremental Revenues	(122)	(1)	(2)	(125)	(57)	(0)	(2)	(12)	(72)
29 R10 Tax Gross-Up Adjustment (Prod Only)	3	0	0	3	1	0	0	0	2
30 Total Revenue Def/ (Sufficiency)	76,234	722	983	77,939	28,090	173	1,043	5,171	34,476
31 Total Base Revenue Requirement	1,400,195	15,004	20,631	1,435,830	649,003	1,207	27,187	136,829	814,227

Production by Class

Alternate Cost of Service Study

PRODUCTION COSTS

	(n)	(o)	(p)	(q)	(r)	(s)
	D-11/Other Primary	D-6.2 Primary Schools	D-8 Interrupt Supply	R-1.1/R-1.2 Metal Melt Process Heat	R-10 Interrupt Supply	Total Primary
1 Rate Base	2,025,919	157,823	67,906	56,010	0	2,307,658
Revenues:						
2 Revenue From Electric Sales	761,701	50,619	29,445	26,252	47,740	915,758
3 D13 Present Revenue	2,650	176	102	91	-	3,020
4 Misc Revenue	2,668	177	105	93	-	3,043
5 Total Adjusted Revenues	767,020	50,972	29,652	26,436	47,740	921,821
Expenses:						
6 Fuel	240,866	15,775	10,574	9,924	7,674	284,814
7 Purchased Power	103,870	7,090	4,080	3,638	40,085	158,764
8 O & M Expense	150,139	10,273	5,930	5,295	(0)	171,637
9 Depreciation	115,841	9,262	3,736	3,013	-	131,853
10 Other (Reg Assets, etc)	-	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-	-
13 Other Taxes	28,296	2,176	964	802	-	32,237
14 Income Taxes	19,089	954	651	561	-	21,256
15 Amortizations	-	-	-	-	-	-
16 Total Expenses	658,101	45,530	25,936	23,233	47,759	800,560
17 Net Oper Income	108,918	5,442	3,716	3,203	(19)	121,261
18 AFUDC & Other	12,687	1,016	408	329	-	14,440
19 Net Adjustments	199	15	7	5	-	226
20 Adj Net Oper Income	121,804	6,473	4,131	3,537	(19)	135,927
21 Rate of Return	6.01%	4.10%	6.08%	6.32%	-25726827.47%	5.89%
22 Return @ 5.9231 %	119,997	9,348	4,022	3,318	0	136,685
23 Income Deficiency	(1,807)	2,874	(109)	(220)	19	757
24 Base Revenue Def / (Sufficiency)	(2,439)	3,880	(147)	(297)	25	1,022
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	30,761	2,464	989	797	-	35,011
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	28,323	6,343	842	500	25	36,034
28 Less: D13 Incremental Revenues	(70)	(5)	(3)	(2)	-	(80)
29 R10 Tax Gross-Up Adjustment (Prod Only)	2	0	0	0	(7)	(5)
30 Total Revenue Def/ (Sufficiency)	28,395	6,348	845	502	19	36,109
31 Total Base Revenue Requirement	790,096	56,968	30,290	26,755	47,759	951,867

Production by Class

Alternate Cost of Service Study

PRODUCTION COSTS

	(t)	(u)	(v)	(w)
	D-9 OPL Residential	D-9 OPL Commercial	E-1 St Lght	E-2 Signals
1 Rate Base	439	1,988	8,962	9,710
Revenues:				
2 Revenue From Electric Sales	257	1,225	5,488	3,817
3 D13 Present Revenue	1	4	19	13
4 Misc Revenue	1	4	33	13
5 Total Adjusted Revenues	259	1,233	5,540	3,843
Expenses:				
6 Fuel	120	544	2,453	1,250
7 Purchased Power	41	187	844	533
8 O & M Expense	60	273	1,229	772
9 Depreciation	21	94	425	548
10 Other (Reg Assets, etc)	-	-	-	-
11 Remove Reg Assets	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-
13 Other Taxes	7	30	135	137
14 Income Taxes	1	16	68	90
15 Amortizations	-	-	-	-
16 Total Expenses	251	1,144	5,154	3,330
17 Net Oper Income	8	89	386	514
18 AFUDC & Other	2	10	46	60
19 Net Adjustments	0	0	1	1
20 Adj Net Oper Income	10	100	433	575
21 Rate of Return	2.34%	5.02%	4.83%	5.92%
22 Return @ 5.9231 %	26	118	531	575
23 Income Deficiency	16	18	98	1
24 Base Revenue Def / (Sufficiency)	21	24	133	1
25 Tree Trim Surge Rev Req (Dist Only)	-	-	-	-
26 Monroe Reg Asset Rev Req (Prod Only)	5	25	111	145
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	27	49	244	146
28 Less: D13 Incremental Revenues	(0)	(0)	(1)	(0)
29 R10 Tax Gross-Up Adjustment (Prod Only)	0	0	0	0
30 Total Revenue Def/ (Sufficiency)	27	49	244	146
31 Total Base Revenue Requirement	284	1,274	5,733	3,963

Distribution by Voltage

Alternate Cost of Service Study
 DISTRIBUTION COSTS

	(a)	(b)	(c)	(j ev)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Total Electric	Residential Secondary	Commercial Secondary	D3.11 EV with DCFC	Primary	Subtransmission	Transmission	D-9 OPL Residential	D-9 OPL Commercial	E-1 St Lght	E-2 Signals
1 Rate Base	13,265,676	8,086,764	3,649,205	7,823	1,015,313	83,659	112,062	12,664	32,509	256,139	9,538
<u>Revenues:</u>											
2 Revenue From Electric Sales	2,274,831	1,428,732	592,444	678	161,015	11,229	11,411	1,850	8,352	57,552	1,571
3 D13 Present Revenue	566	356	147	0	40	3	3	0	2	14	0
4 Misc Revenue	80,620	59,388	11,033	20	3,557	2,086	3,664	22	253	573	26
5 Total Adjusted Revenues	2,356,017	1,488,475	603,624	697	164,611	13,318	15,077	1,872	8,606	58,139	1,597
<u>Expenses:</u>											
6 Fuel	-	-	-	-	-	-	-	-	-	-	-
7 Purchased Power	-	-	-	-	-	-	-	-	-	-	-
8 O & M Expense	688,750	474,143	157,061	287	39,764	2,088	3,483	454	1,564	9,448	457
9 Depreciation	749,247	459,959	201,948	440	47,216	3,210	3,670	1,444	3,216	27,633	509
10 Other (Reg Assets, etc)	-	-	-	-	-	-	-	-	-	-	-
11 Remove Reg Assets	-	-	-	-	-	-	-	-	-	-	-
12 Accretion of Loss/ Gain on Sale	-	-	-	-	-	-	-	-	-	-	-
13 Other Taxes	259,987	160,003	69,242	148	19,028	1,563	2,076	345	826	6,578	178
14 Income Taxes	88,937	53,301	23,703	(24)	7,921	873	790	(50)	405	1,957	61
15 Amortizations	-	-	-	-	-	-	-	-	-	-	-
16 Total Expenses	1,786,921	1,147,407	451,954	851	113,928	7,733	10,020	2,194	6,012	45,615	1,206
17 Net Oper Income	569,097	341,068	151,670	(154)	50,683	5,584	5,057	(321)	2,594	12,524	391
18 AFUDC & Other	1,171	714	322	1	90	7	10	1	3	23	1
19 Net Adjustments	1,388	846	382	1	106	9	12	1	3	27	1
20 Adj Net Oper Income	571,655	342,628	152,373	(152)	50,879	5,601	5,079	(319)	2,600	12,573	393
21 Rate of Return	4.31%	4.24%	4.18%	-1.94%	5.01%	6.69%	4.53%	-2.52%	8.00%	4.91%	4.12%
22 Return @ 5.9231 %	785,739	478,987	216,146	463	60,138	4,955	6,638	750	1,926	15,171	565
23 Income Deficiency	214,084	136,359	63,773	615	9,260	(645)	1,559	1,069	(675)	2,598	172
24 Base Revenue Def / (Sufficiency)	288,935	184,035	86,070	831	12,497	(871)	2,104	1,442	(911)	3,506	232
25 Tree Trim Surge Rev Req (Dist Only)	18,786	12,222	5,657	13	718	0	1	6	22	132	15
26 Monroe Reg Asset Rev Req (Prod Only)	-	-	-	-	-	-	-	-	-	-	-
27 Base Revenue Def/ (Sufficiency) w Tree Trim Surge & Monroe	307,721	196,257	91,726	843	13,215	(871)	2,105	1,448	(889)	3,639	247
28 Less: D13 Incremental Revenues	59	37	15	0	4	0	0	0	0	1	0
29 R10 Tax Gross-Up Adjustment (Prod Only)	-	-	-	-	-	-	-	-	-	-	-
30 Total Revenue Def/ (Sufficiency)	307,663	196,220	91,711	843	13,211	(871)	2,105	1,448	(889)	3,637	247
31 Total Base Revenue Requirement	2,582,494	1,624,952	684,155	1,521	174,226	10,358	13,515	3,298	7,462	61,189	1,818

CAPACITY CHARGE

Alternate Cost of Service Study

75-0-25

PRODUCTION COSTS

(a)	(b)	(c)	(d)	(e)
Total Electric	Total Residential	Total Commercial Secondary	Total Primary	E-1 St Lgt D9 OPL E-2 Signals

CAPACITY COSTS DETERMINATION

1	Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 29)	\$	3,213,177					
2	Less Fuel (Exh A-16 Sch F1.1 Line 6)		(914,888)					
3	Less MERC Rev Req (Exh A-16, Sch F1.5 Page 6 Line 9)		(6,463)					
4	Less MISO Energy in PP (Exh A-13 Sch C4 Lines 21-22)		(40,376)					
5	Less Other Energy in PP (WP A16 F1 Sch 11.5 Line 14)		(260,787)					
6	Less Variable O&M (Exh A-16 Sch F1.5 Page 5 Line 8)		<u>(33,569)</u>					
7	Subtotal	\$	1,957,094					
8								
9	Proj 2025 Energy Sales Rev Net of Fuel (per A-26, Sch P3, Line 23)		<u>(983,347)</u>					
10								
11	Capacity Revenue Requirement (Line 6 + Line 7)	\$	973,747					
12								
	SRM Capacity Charge Demand (DTE 2022 10-k, pg 9 / net gen capacity							
13	11,717 MW + long-term contracts 560 MW)		12,277 MW					
14								
15	SRM Capacity Charge per MW-Year (Line 11 / Line 13 x 1,000)		79,315					
16								
17	SRM Capacity Charge per MW-Day (Line 15 / 365)		<u>217.30</u>					
18								
19	<u>Allocator</u>							
20	Sch 200B 4 CP Excl R10 (alloc. 251)		100.0000	51.7438	25.3228	22.8450	0.0884	
21								
22	<u>Revenue Requirement</u>							
23	Capacity Revenue Requirement (Line 8 * Line 9/100)	\$	973,747	\$ 503,854	\$ 246,580	\$ 222,453	\$ 860	
24	Non-Capacity Revenue Requirement (Line 12 less Line 10)		<u>2,239,430</u>	<u>931,976</u>	<u>567,647</u>	<u>729,414</u>	<u>10,393</u>	
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)	\$	<u>3,213,177</u>	<u>\$ 1,435,830</u>	<u>\$ 814,227</u>	<u>\$ 951,867</u>	<u>\$ 11,253</u>	

CAPACITY CHARGE

Alternate Cost of Service Study

75-0-25

PRODUCTION COSTS

	(f)	(g)	(i)	(j)	(g)	(g)	(h)	(i)	(j)
	D-1.11/Other Residential Service	D-1.2 Time Of Use	D-2 Residential Space Ht	Total Residential	D-3/Other General Service	D3.11 EV with DCFC	D-3.2 Secondary Schools	D-4 Lg Genl Service	Total Commercial Secondary
<u>Allocator</u>									
20 Sch 200B 4 CP Excl R10 (alloc. 251)	50.8017	0.4196	0.5225	51.7438	20.4848	0.0344	0.8270	3.9766	25.3228
<u>Revenue Requirement</u>									
23 Capacity Rev Req (P1 Line 7 * Line 8/100)	\$ 494,680	\$ 4,086	\$ 5,088	\$ 503,854	\$ 199,470	\$ 335	\$ 8,053	\$ 38,722	\$ 246,580
24 Non-Capacity Revenue Requirement (Line 12 less Line 10)	905,515	10,918	15,543	931,976	449,533	872	19,134	98,108	567,647
25 Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)	\$ 1,400,195	\$ 15,004	\$ 20,631	\$ 1,435,830	\$ 649,003	\$ 1,207	\$ 27,187	\$ 136,829	\$ 814,227

CAPACITY CHARGE

Alternate Cost of Service Study

75-0-25

PRODUCTION COSTS

(k)	(l)	(m)	(n)	(o)	(p)
D-11/Other Primary	D-6.2 Primary Schools	D-8 Interrupt Supply	R-1.1/R-1.2 Metal Melt Process Heat	R-10 Interrupt Supply	Total Primary

Allocator

20	Sch 200B 4 CP Excl R10 (alloc. 251)	20.1398	1.8003	0.5316	0.3733	-	22.8450	-

Revenue Requirement

23	Capacity Rev Req (P1 Line 7 * Line 8/100)	\$ 196,111	\$ 17,531	\$ 5,176	\$ 3,635	\$ -	\$ 222,453
24	Non-Capacity Revenue Requirement (Line 12 less Line 10)	<u>593,985</u>	<u>39,437</u>	<u>25,114</u>	<u>23,120</u>	<u>47,759</u>	<u>729,414</u>
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)	<u>\$ 790,096</u>	<u>\$ 56,968</u>	<u>\$ 30,290</u>	<u>\$ 26,755</u>	<u>\$ 47,759</u>	<u>\$ 951,867</u>

CAPACITY CHARGE			
<u>Alternate Cost of Service Study</u>			
75-0-25			
PRODUCTION COSTS			
(q)	(r)	(s)	(t)
<u>D-9 OPL Residential</u>	<u>D-9 OPL Commercial</u>	<u>E-1 St Lght</u>	<u>E-2 Signals</u>

<u>Allocator</u>					
20	Sch 200B 4 CP Excl R10 (alloc. 251)	-	-	-	0.0884
<u>Revenue Requirement</u>					
23	Capacity Rev Req (P1 Line 7 * Line 8/100)	\$ -	\$ -	\$ -	\$ 860
24	Non-Capacity Revenue Requirement (Line 12 less Line 10)	<u>284</u>	<u>1,274</u>	<u>5,733</u>	<u>3,103</u>
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)	<u>\$ 284</u>	<u>\$ 1,274</u>	<u>\$ 5,733</u>	<u>\$ 3,963</u>

Case No.: U-21534

Exhibit: A-16

Schedule: F2

Witness: A. Willis

Page: 1 of 4

**DTE Electric Company
Case No. U-21534
Present and Proposed Revenue
by Rate Schedule**

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
by Rate Schedule

Case No.: U-21534
Exhibit: A-16
Schedule: F2
Witness: A. Willis
Page: 2 of 4

Total Revenues

	(a)	(b)	(c)	(d)	(e)
Line No.	Residential	Total Present Revenue (\$000's)	Total Proposed Revenue (\$000's)	Total Net Increase/ (Decrease) (\$000's)	Total Net Increase/ (Decrease) (%)
1	D1/D1.6 Residential	\$48,110	\$50,386	\$2,276	4.7%
2	D1.1 Int. Air	\$53,003	\$58,552	\$5,549	10.5%
3	D1.2 TOD	\$32,649	\$35,957	\$3,308	10.1%
4	D1.7 TOD	\$15,366	\$17,134	\$1,767	11.5%
5	D1.8 Dynamic	\$29,279	\$32,205	\$2,927	10.0%
6	D1.9 Elec. Vehicle	\$1,992	\$2,203	\$211	10.6%
7	D1.11 Time of Use	\$2,633,702	\$2,886,147	\$252,445	9.6%
8	D2 Elec. Space Heat	\$47,084	\$51,782	\$4,698	10.0%
9	D5 Res. Water Ht.	\$14,146	\$15,701	\$1,555	11.0%
10	Total Residential	\$2,875,332	\$3,150,067	\$274,735	9.6%
11					
12	Secondary				
13	D1.1 Int. Air	\$708	\$769	\$61	8.6%
14	D1.7 TOD	\$1,581	\$1,749	\$168	10.6%
15	D1.8 Dynamic	\$136	\$148	\$12	8.8%
16	D 1.9 Elec Vehicle	\$62	\$68	\$6	9.9%
17	D3 Gen. Serv.	\$1,066,344	\$1,160,898	\$94,553	8.9%
18	D3.1 Unmetered	\$11,064	\$12,191	\$1,127	10.2%
19	D3.2 Sec. Educ.	\$60,733	\$67,235	\$6,501	10.7%
20	D3.3 Interruptible	\$7,083	\$7,790	\$707	10.0%
21	D3.5 Charging Serv.	\$0	\$0	\$0	-
22	D4 Lg. Gen. Serv.	\$256,631	\$278,394	\$21,763	8.5%
23	D5 Com. Wat. Ht.	\$1,085	\$1,193	\$107	9.9%
24	E1.1 Eng. St. Ltg.	\$1,152	\$1,267	\$115	10.0%
25	R7 Greenhs. Ltg.	\$419	\$464	\$45	10.7%
26	R8 Space Cond.	\$9,537	\$10,420	\$884	9.3%
27	Total Secondary	\$1,416,535	\$1,542,585	\$126,050	8.9%
28					
29	Primary				
30	D11 Prim. Supply	\$959,228	\$998,800	\$39,572	4.1%
31	D12 Exp. Lrg Cust	\$0	\$0	\$0	-
32	D6.2 Pri. Educ.	\$74,835	\$82,402	\$7,567	10.1%
33	D8 Int. Primary	\$39,805	\$41,225	\$1,421	3.6%
34	D10 El. Schools	\$2,911	\$2,977	\$65	2.2%
35	R1.1 Alt. Mtl. Melt.	\$8,244	\$8,580	\$336	4.1%
36	R1.2 El. Pr. Htg.	\$30,125	\$31,291	\$1,165	3.9%
37	R3 Standby	\$8,526	\$8,754	\$229	2.7%
38	R10 Int. Supply	\$52,885	\$53,484	\$599	1.1%
39	Total Primary	\$1,176,559	\$1,227,513	\$50,954	4.3%
40					
41	D13 XL	\$11,111	\$10,892	(\$219)	(2.0%)
42					
43	Other				
44	D9 Protective Ltg.	\$12,439	\$13,068	\$629	5.1%
45	E1 Muni Street Ltg	\$63,859	\$67,751	\$3,892	6.1%
46	E2 Traffic Lights	\$5,468	\$5,862	\$394	7.2%
47	Total Other	\$81,766	\$86,680	\$4,914	6.0%
48					
49	Total All Classes	\$5,561,302	\$6,017,737	\$456,434	8.2%

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
by Rate Schedule

Case No.: U-21534
Exhibit: A-16
Schedule: F2
Witness: A. Willis
Page: 3 of 4

Power Supply Revenues

Line No.	(a) Residential	(b) Power Supply Sales (MWH)	(c) Present Revenue (\$000's)	(d) Increase/ (Decrease) (\$000's)	(e) Proposed Revenue (\$000's)	(f) Capacity Revenue (\$000's)	(g) Non-Capacity Revenue (\$000's)
1	D1/D1.6 Residential	332,538	\$30,327	\$1,745	\$32,072	\$11,331	\$20,742
2	D1.1 Int. Air	321,827	\$22,915	\$1,319	\$24,233	\$8,561	\$15,672
3	D1.2 TOD	196,822	\$14,282	\$721	\$15,004	\$4,086	\$10,918
4	D1.7 TOD	108,929	\$5,827	\$335	\$6,162	\$2,177	\$3,985
5	D1.8 Dynamic	166,773	\$12,765	\$735	\$13,500	\$4,769	\$8,730
6	D1.9 Elec. Vehicle	12,539	\$801	\$46	\$847	\$299	\$548
7	D1.11 Time of Use	13,748,482	\$1,246,609	\$71,746	\$1,318,355	\$465,754	\$852,601
8	D2 Elec. Space Heat	282,672	\$19,648	\$983	\$20,630	\$5,088	\$15,542
9	<u>D5 Res. Water Ht.</u>	97,669	\$4,717	\$272	\$4,989	\$1,763	\$3,226
10	Total Residential	15,268,251	\$1,357,891	\$77,902	\$1,435,793	\$503,827	\$931,965
11							
12	Secondary						
13	D1.1 Int. Air	5,153	\$358	\$16	\$374	\$115	\$259
14	D1.7 TOD	15,388	\$714	\$32	\$746	\$229	\$517
15	D1.8 Dynamic	972	\$77	\$3	\$80	\$25	\$56
16	D1.9 Elec. Vehicle	342	\$28	\$2	\$30	\$10	\$19
17	D3 Gen. Serv.	7,457,882	\$604,536	\$27,526	\$632,062	\$194,249	\$437,812
18	D3.1 Unmetered	89,133	\$6,141	\$280	\$6,420	\$1,973	\$4,447
19	D3.2 Sec. Educ.	331,944	\$26,144	\$1,042	\$27,186	\$8,053	\$19,133
20	D3.3 Interruptible	54,552	\$3,695	\$168	\$3,863	\$1,187	\$2,676
21	D3.5 Charging Serv.	0	\$0	\$0	\$0	\$0	\$0
22	D4 Lg. Gen. Serv.	1,738,514	\$131,658	\$5,168	\$136,827	\$38,720	\$98,107
23	D5 Com. Wat. Ht.	9,881	\$472	\$21	\$493	\$152	\$342
24	E1.1 Eng. St. Ltg.	10,256	\$573	\$26	\$599	\$184	\$415
25	R7 Greenhs. Ltg.	4,153	\$192	\$9	\$201	\$62	\$139
26	<u>R8 Space Cond.</u>	73,342	\$5,164	\$235	\$5,399	\$1,659	\$3,740
27	Total Secondary	9,791,512	\$779,751	\$34,529	\$814,280	\$246,618	\$567,662
28							
29	Primary						
30	D11 Prim. Supply	11,505,383	\$754,111	\$28,127	\$782,238	\$194,124	\$588,115
31	D12 Exp. Lrg Cust	0	\$0	\$0	\$0	\$0	\$0.00
32	D6.2 Pri. Educ.	699,018	\$50,619	\$6,347	\$56,966	\$17,530	\$39,437
33	D8 Int. Primary	509,730	\$29,445	\$845	\$30,290	\$5,176	\$25,114
34	D10 El.Schools	20,890	\$1,710	\$64	\$1,774	\$440	\$1,334
35	R1.1 Alt. Mtl. Melt.	125,163	\$6,971	\$163	\$7,134	\$1,011	\$6,123
36	R1.2 El. Pr. Htg.	347,461	\$19,281	\$340	\$19,620	\$2,623	\$16,997
37	R3 Standby	74,189	\$5,880	\$190	\$6,069	\$1,537	\$4,533
38	<u>R10 Int. Supply</u>	998,081	\$47,740	\$19	\$47,759	\$0	\$47,759
39	Total Primary	14,279,913	\$915,758	\$36,093	\$951,851	\$222,441	\$729,410
40							
41	D13 XL	200,000	\$10,496	(\$278)	\$10,218	\$3,028	\$7,190
42							
43	Other						
44	<u>D9 Protective Ltg.</u>	33,226	\$1,482	\$68	\$1,550	\$0	\$1,550
45	E1 Muni Street Ltg	123,056	\$5,488	\$252	\$5,740	\$0	\$5,740
46	<u>E2 Traffic Lights</u>	59,731	\$3,817	\$146	\$3,963	\$860	\$3,103
47	Total Other	216,013	\$10,787	\$466	\$11,253	\$860	\$10,393
48							
49	Total All Classes	39,755,689	\$3,074,683	\$148,713	\$3,223,395	\$976,775	\$2,246,621

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
by Rate Schedule

Case No.: U-21534
Exhibit: A-16
Schedule: F2
Witness: A. Willis
Page: 4 of 4

Distribution Revenues

Line No.	(a) Residential	(b) Distribution Sales (MWH)	(c) Present Revenue (\$000's)	(d) Increase/ (Decrease) (\$000's)	(e) Proposed Revenue (\$000's)
1	D1/D1.6 Residential	332,538	\$17,783	\$531	\$18,313
2	D1.1 Int. Air	321,827	\$30,089	\$4,230	\$34,318
3	D1.2 TOD	196,822	\$18,367	\$2,587	\$20,954
4	D1.7 TOD	108,929	\$9,540	\$1,432	\$10,971
5	D1.8 Dynamic	166,773	\$16,514	\$2,192	\$18,706
6	D1.9 Elec. Vehicle	12,539	\$1,192	\$165	\$1,356
7	D1.11 Time of Use	13,748,482	\$1,387,093	\$180,699	\$1,567,792
8	D2 Elec. Space Heat	282,672	\$27,436	\$3,715	\$31,151
9	D5 Res. Water Ht.	97,669	\$9,428	\$1,284	\$10,712
10	Total Residential	15,268,251	\$1,517,440	\$196,834	\$1,714,274
11					
12	Secondary				
13	D1.1 Int. Air	5,164	\$350	\$45	\$395
14	D1.7 TOD	15,586	\$867	\$135	\$1,003
15	D1.8 Dynamic	972	\$59	\$8	\$67
16	D1.9 Elec Vehicle	342	\$34	\$4	\$38
17	D3 Gen. Serv.	7,719,328	\$461,808	\$67,028	\$528,836
18	D3.1 Unmetered	89,133	\$4,924	\$847	\$5,771
19	D3.2 Sec. Educ.	628,745	\$34,590	\$5,459	\$40,049
20	D3.3 Interruptible	62,065	\$3,388	\$539	\$3,927
21	D3.5 Charging Serv.	0	\$0	\$0	\$0
22	D4 Lg. Gen. Serv.	1,993,249	\$124,973	\$16,595	\$141,567
23	D5 Com. Wat. Ht.	9,886	\$614	\$86	\$700
24	E1.1 Eng. St. Ltg.	10,256	\$579	\$89	\$668
25	R7 Greenhs. Ltg.	4,153	\$227	\$36	\$263
26	R8 Space Cond.	74,713	\$4,372	\$649	\$5,021
27	Total Secondary	10,613,593	\$636,784	\$91,521	\$728,305
28					
29	Primary				
30	D11 Prim. Supply	14,553,177	\$205,117	\$11,445	\$216,562
31	D12 Exp. Lrg Cust	0	\$0	\$0	\$0
32	D6.2 Pri. Educ.	1,093,792	\$24,215	\$1,220	\$25,436
33	D8 Int. Primary	642,991	\$10,360	\$576	\$10,936
34	D10 El.Schools	34,286	\$1,201	\$2	\$1,203
35	R1.1 Alt. Mtl. Melt.	125,163	\$1,273	\$173	\$1,446
36	R1.2 El. Pr. Htg.	369,846	\$10,845	\$825	\$11,670
37	R3 Standby	66,802	\$2,646	\$39	\$2,685
38	R10 Int. Supply	998,081	\$5,145	\$580	\$5,724
39	Total Primary	17,884,137	\$260,801.307	\$14,860	\$275,662
40					
41	D13 XL	200,000	\$615	\$59	\$674
42					
43	Other				
44	D9 Protective Ltg.	33,226	\$10,957	\$561	\$11,518
45	E1 Muni Street Ltg	123,056	\$58,370	\$3,640	\$62,010
46	E2 Traffic Lights	59,731	\$1,651	\$248	\$1,899
47	Total Other	216,013	\$70,979	\$4,448	\$75,427
48					
49	Total All Classes	44,181,994	\$2,486,620	\$307,722	\$2,794,341

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
R. A. Bellini
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DTE Electric Company
Case No. U-21534
Present and Proposed Revenue

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Non-Transmitting Meter - D1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	90,377	MWh	\$0.07809	7,058	\$0.06237	5,637
3	Capacity Charges:						
4	First 17 KWH/Day	50,492	MWh	\$0.01128	570	\$0.02932	1,480
5	Excess	39,884	MWh	\$0.01626	649	\$0.04227	1,686
6	Power Supply Subtotal	90,377	MWh	9.16¢	8,276	9.74¢	8,803
7							
8	PSCR	90,377	MWh	\$0.00000	0	\$0.00000	0
9	REPS	9,516	Meters	\$0.00000	0	\$0.00000	0
10	Total Full Service Power Supply	90,377	MWh	9.16¢	8,276	9.74¢	8,803
11							
12	Full Service Distribution	Quantity	Units				
13							
14	Service Charge	9,516	Cust.	\$8.50	971	\$8.50	971
15	Income Assistance	179	Cust.	(\$8.50)	(18)	(\$8.50)	(18)
16	Senior Citizen Provision	501	Cust.	(\$4.25)	(26)	(\$4.25)	(26)
17							
18	Distribution Charge	90,377	MWh	\$0.08137	7,354	\$0.09451	8,542
19	Distribution System	90,377	MWh	9.16¢	8,281	10.48¢	9,469
20	IRM	90,377	MWh	\$0.000941	85	\$0.000941	85
21	Nuclear Decomm.	90,377	MWh	\$0.000882	80	\$0.000882	80
22	Energy Waste Reduction	90,377	MWh	\$0.002552	231	\$0.002552	231
23	LIEAF	9,516	Cust.	\$0.88	100	\$0.88	100
24	Distribution Surcharges	90,377	MWh	0.55¢	496	0.55¢	496
25							
26	Total Full Service Distribution			9.71¢	8,777	11.03¢	9,965
27	Total Full Service D1	90,377	MWh	18.87¢	17,052	20.77¢	18,768
28							
29	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
30							
31	Capacity Charges:						
32	First 17 KWH/Day	0	MWh	\$0.01128	0	\$0.02932	0
33	Excess	0	MWh	\$0.01626	0	\$0.04227	0
34	Capacity Total	0	MWh		0		0
35							
36	Distribution Charges						
37	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
38	Income Assistance	0	Cust.	(\$8.50)	0	(\$8.50)	0
39	Senior Citizen Provision	0	Cust.	(\$4.25)	0	(\$4.25)	0
40							
41	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
42	Distribution System	0	MWh		0		0
43	IRM	0	MWh	\$0.000941	0	\$0.000941	0
44	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
45	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
46	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
47	Distribution Surcharges	0	MWh		0		0
48							
49	Total Choice D1	0	MWh		0		0
50							
51	Total D1	90,377	MWh	18.87¢	17,052	20.77¢	18,768
52	Increase/Decrease (\$)						1,716

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Space-Conditioning Service Rate - D1.1 Residential

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	321,827	MWh	\$0.06085	19,583	\$0.04870	15,672
3	Capacity Charges						
4	Summer Energy	300,672	MWh	\$0.01089	3,274	\$0.02799	8,414
5	Winter Winter	21,155	MWh	\$0.00270	57	\$0.00694	147
6	Power Supply Subtotal	321,827	MWh		22,915		24,233
7							
8	PSCR	321,827	MWh	\$0.00000	0	\$0.00000	0
9	Total Full Service Power Supply	321,827	MWh	7.12¢	22,915	7.53¢	24,233
10							
11	Full-Service Distribution	Quantity	Units				
12		Customers	Months				
13	Service Charge (June-Oct)	255,750	5	\$1.95	2,494	\$1.95	2,494
14							
15	Distribution Charge	321,827	MWh	\$0.08137	26,187	\$0.09451	30,417
16	Distribution System	321,827	MWh	8.91¢	28,681	10.23¢	32,910
17	IRM	321,827	MWh	\$0.000941	303	\$0.000941	303
18	Nuclear Decomm.	321,827	MWh	\$0.000882	284	\$0.000882	284
19	Energy Waste Reduction	321,827	MWh	\$0.002552	821	\$0.002552	821
20	Distribution Surcharges	321,827	MWh	0.44¢	1,408	0.44¢	1,408
21							
22	Total Full Service Distribution	321,827	MWh	9.35¢	30,089	10.66¢	34,318
23	Total Full-Service D1.1	321,827	MWh	16.47¢	53,003	18.19¢	58,552
24							
25	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26							
27	Capacity Charges						
28	Summer Energy	0	MWh	\$0.01089	0	\$0.02799	0
29	Winter Energy	0	MWh	\$0.00270	0	\$0.00694	0
30	Capacity Total	0	MWh		0		0
31							
32	Distribution Charges						
33		Customers	Months				
34	Service Charge (June-Oct)	0	5	\$1.95	0	\$1.95	0
35							
36	Distribution Energy	0	MWh	\$0.08137	0	\$0.09451	0
37	Distribution System	0	MWh		0		0
38	IRM	0	MWh	0.000941	0	0.000941	0
39	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
40	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
41	Distribution Surcharges	0	MWh		0		0
42							
43	Total Choice D1.1	0	MWh		0		0
44							
45	Total D1.1	321,827	MWh	16.47¢	53,003	18.19¢	58,552
46	Increase/Decrease (\$)						5,549

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Enhanced TOU - D1.2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 4 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge						
3	Summer:						
4	On-Peak	19,491	MWh	\$0.13949	\$2,719	\$0.11955	2,330
5	Off-Peak	58,273	MWh	\$0.04696	\$2,737	\$0.04025	2,345
6	Winter:						
7	On-Peak	26,292	MWh	\$0.11783	\$3,098	\$0.10098	2,655
8	Off-Peak	92,765	MWh	\$0.04512	\$4,186	\$0.03867	3,587
9	Capacity Charges						
10	Summer:						
11	On-Peak	19,491	MWh	\$0.01690	329	\$0.04474	872
12	Off-Peak	58,273	MWh	\$0.00569	332	\$0.01506	878
13	Winter:						
14	On-Peak	26,292	MWh	\$0.01427	375	\$0.03779	994
15	Off-Peak	92,765	MWh	\$0.00547	507	\$0.01447	1,343
16	Power Supply Subtotal	196,822	MWh		14,282		15,004
17							
18	PSCR	196,822	MWh	\$0.00000	0	\$0.00000	0
19	REPS	13,500	Meters	\$0.00000	0	\$0.00000	0
20	Total Full Service Power Supply	196,822	MWh	7.26¢	14,282	7.62¢	15,004
21							
22	Full Service Distribution	Quantity	Units				
23							
24	Service Charge	13,500	Cust.	\$8.50	1,377	\$8.50	1,377
25	Income Assistance	113	Cust.	(\$8.50)	(12)	(\$8.50)	(12)
26	Senior Citizen Provision	350	Cust.	(\$4.25)	(18)	(\$4.25)	(18)
27							
28	Distribution Energy	196,822	MWh	\$0.08137	16,015	\$0.09451	18,602
29	Distribution System	196,822	MWh	8.82¢	17,363	10.14¢	19,950
30	IRM	196,822	MWh	\$0.000941	185	\$0.000941	185
31	Nuclear Decomm.	196,822	MWh	\$0.000882	174	\$0.000882	174
32	Energy Waste Reduction	196,822	MWh	\$0.002552	502	\$0.002552	502
33	LIEAF	13,500	Cust.	\$0.88	143	\$0.88	143
34	Distribution Surcharges	196,822	MWh	0.51¢	1,004	0.51¢	1,004
35							
36	Total Full Service Distribution	196,822	MWh	9.33¢	18,367	10.65¢	20,954
37	Total Full-Service D1.2	196,822	MWh	16.59¢	32,649	18.27¢	35,957
38							
39	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
40							
41	Capacity Charges						
42	Summer:						
43	On-Peak	0	MWh	\$0.01690	0	\$0.04474	0
44	Off-Peak	0	MWh	\$0.00569	0	\$0.01506	0
45	Winter:						
46	On-Peak	0	MWh	\$0.01427	0	\$0.03779	0
47	Off-Peak	0	MWh	\$0.00547	0	\$0.01447	0
48	Capacity Total	0	MWh		0		0
49							
50	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
51	Income Assistance	0	Cust.	(\$8.50)	0	(\$8.50)	0
52	Senior Citizen Provision		Cust.	(\$4.25)	0	(\$4.25)	0
53							
54	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
55	Distribution System	0	MWh		0		0
56	IRM	0	MWh	\$0.000941	0	\$0.000941	0
57	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
58	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
59	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
60	Distribution Surcharges	0	MWh		0		0
61							
62	Total Choice D1.2	0	MWh		0		0
63							
64	Total D1.2	196,822	MWh	16.59¢	32,649	18.27¢	35,957
65	Increase/Decrease (\$)						3,308

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Special Low Income Pilot Rate - D1.6

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	242,162	MWh	\$0.07809	18,910	\$0.06237	15,105
3	Capacity Charges						
4	First 17 KWH/Day	159,969	MWh	\$0.01128	1,804	\$0.02932	4,690
5	Excess	82,193	MWh	\$0.01626	1,336	\$0.04227	3,474
6	Power Supply Subtotal	242,162	MWh	9.11¢	22,051	9.61¢	23,269
7							
8	PSCR	242,162	MWh	\$0.00000	0	\$0.00000	0
9	REPS	32,000	Meters	\$0.00000	0	\$0.00000	0
10	Total Full Service Power Supply	242,162	MWh	9.11¢	22,051	9.61¢	23,269
11							
12	Full Service Distribution	Quantity	Units				
13							
14	Service Charge	32,000	Cust.	\$8.50	3,264	\$8.50	3,264
15	Income Assistance	32,000	Cust.	(\$40.00)	(15,360)	(\$50.00)	(19,200)
16							
17	Distribution Charge	242,162	MWh	\$0.08137	19,705	\$0.09451	22,887
18	Distribution System	242,162	MWh	3.14¢	7,609	2.87¢	6,951
19	IRM	242,162	MWh	\$0.000941	228	\$0.000941	228
20	Nuclear Decomm.	242,162	MWh	\$0.000882	214	\$0.000882	214
21	Energy Waste Reduction	242,162	MWh	\$0.002552	618	\$0.002552	618
22	LIEAF	32,000	Cust.	\$0.88	338	\$0.88	338
23	Distribution Subtotal	242,162	MWh	0.58¢	1,397	0.58¢	1,397
24							
25	Total Full Service Distribution			3.72¢	9,006	3.45¢	8,349
26	Total Full Service D1.6	242,162	MWh	12.83¢	31,057	13.06¢	31,618
27							
28	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
29							
30	Capacity Charges						
31	First 17 KWH/Day	0	MWh	\$0.01128	0	\$0.02932	0
32	Excess	0	MWh	\$0.01626	0	\$0.04227	0
33	Total Capacity	0			0		0
34							
35	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
36	Income Assistance	0	Cust.	(\$40.00)	0	(\$50.00)	0
37							
38	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
39	Distribution System	0	MWh		0		0
40	IRM	0	MWh	0.000941	0	0.000941	0
41	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
42	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
43	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
44	Distribution Subtotal	0	MWh		0		0
45							
46	Total Choice D1.6	0	MWh		0		0
47							
48	Total D1.6	242,162	MWh	12.83¢	31,057	13.06¢	31,618
49	Increase/Decrease (\$)						560

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Geothermal Time of Day Service Rate - Residential D1.7

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	108,929	MWh	\$0.04582	\$4,991		
3	Summer Energy (11 a.m. Peak Start)						
4	On-Peak	6,541	MWh			\$0.09310	609
5	Off-Peak	15,676	MWh			\$0.03084	483
6	Winter Energy (11 a.m. Peak Start)						
7	On-Peak	17,639	MWh			\$0.04023	710
8	Off-Peak	69,072	MWh			\$0.03161	2,183
9							
10	Capacity Charges:						
11	Summer Energy (11 a.m. Peak Start)						
12	On-Peak	6,541	MWh	\$0.04248	\$278	\$0.05086	333
13	Off-Peak	15,676	MWh	\$0.00001	\$0	\$0.01685	264
14	Winter Energy (11 a.m. Peak Start)						
15	On-Peak	17,639	MWh	\$0.01717	\$303	\$0.02197	388
16	Off-Peak	69,072	MWh	\$0.00369	\$255	\$0.01727	1,193
17	Power Supply Subtotal	108,929	MWh		\$5,827		6,162
18							
19	PSCR	108,929	MWh	\$0.00000	0	\$0.00000	0
20	Total Power Supply	108,929	MWh	5.35¢	5,827	5.66¢	6,162
21							
22	Full Service Distribution	Quantity	Units				
23							
24	Service Charge (\$/day)	8,160	Cust.	\$0.067	200	\$0.067	200
25							
26	Distribution Charge	108,929	MWh	\$0.08137	8,864	\$0.09451	10,295
27	Distribution System	108,929	MWh	8.32¢	9,063	9.63¢	10,495
28	IRM	108,929	MWh	\$0.000941	103	\$0.000941	103
29	Nuclear Decomm.	108,929	MWh	\$0.000882	96	\$0.000882	96
30	Energy Waste Reduction	108,929	MWh	\$0.002552	278	\$0.002552	278
31	Distribution Surcharges	108,929	MWh	0.44¢	477	0.44¢	477
32							
33	Total Full Service Distribution	108,929	MWh	8.76¢	9,540	10.07¢	10,971
34	Total Full-Service D1.7	108,929	MWh	14.11¢	15,366	15.73¢	17,134
35							
36	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
37							
38	Capacity Charges:						
39	Summer Energy (11 a.m. Peak Start)						
40	On-Peak	0	MWh	\$0.04248	0	\$0.05086	0
41	Off-Peak	0	MWh	\$0.00001	0	\$0.01685	0
42	Winter Energy (11 a.m. Peak Start)						
43	On-Peak	0	MWh	\$0.01717	0	\$0.02197	0
44	Off-Peak	0	MWh	\$0.00369	0	\$0.01727	0
45	Total Capacity	0	MWh		0		0
46							
47	Distribution Charges						
48	Service Charge (\$/day)	0	Cust.	\$0.067	0	\$0.067	0
49							
50	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
51	Distribution System	0	MWh		0		0
52	IRM	0	MWh	\$0.000941	0	\$0.000941	0
53	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
54	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
55	Distribution Surcharges	0	MWh		0		0
56							
57	Total Choice D1.7	0	MWh		0		0
58							
59	Total D1.7	108,929	MWh	14.11¢	15,366	15.73¢	17,134
60	Increase/Decrease (\$)						1,767

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Dynamic Peak Pricing - D1.8

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
	Full Service Power Supply	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Non-Capacity Charge						
2	Off-Peak (11pm-7am)	87,291	MWh	\$0.03940	3,439	\$0.03098	2,704
3	Mid-Peak (7pm-11pm, 7am-3pm)	57,481	MWh	\$0.07635	4,389	\$0.06004	3,451
4	On-Peak (3pm-7pm)	21,918	MWh	\$0.14747	3,232	\$0.11702	2,565
5	Critical Peak (3pm-7pm)	83	MWh	\$0.14747	12	\$0.11702	10
6	Capacity Charges:						
7	Off-Peak (11pm-7am)	87,291	MWh	\$0.00590	515	\$0.01678	1,465
8	Mid-Peak (7pm-11pm, 7am-3pm)	57,481	MWh	\$0.01144	658	\$0.03252	1,869
9	On-Peak (3pm-7pm)	21,918	MWh	\$0.02067	453	\$0.06229	1,365
10	Critical Peak (3pm-7pm)	83	MWh	\$0.80253	67	\$0.83298	69
11	Power Supply Subtotal	166,773	MWh	\$0.07654	12,765	\$0.08095	13,500
12							
13	PSCR	166,773	MWh	\$0.00000	0	\$0.00000	0
14	REPS	21,200	Cust	\$0.00000	0	\$0.00000	0
15	Total Full Service Power Supply	166,773	MWh	7.65¢	12,765	8.09¢	13,500
16							
17	Full Service Distribution	Quantity	Units				
18							
19	Sales Applied to Min.		MWh				
20	Service Charge	21,200	Cust.	\$8.50	2,162	\$8.50	2,162
21	Income Assistance	1,416	Cust.	(\$8.50)	(144)	(\$8.50)	(144)
22	Senior Citizen Provision	549	Cust.	(\$4.25)	(28)	(\$4.25)	(28)
23							
24	Distribution Charge	166,773	MWh	\$0.08137	13,570	\$0.09451	15,762
25	Distribution System	166,773	MWh	9.33¢	15,560	10.64¢	17,752
26	IRM	166,773	MWh	\$0.000941	157	\$0.000941	157
27	Nuclear Decomm.	166,773	MWh	\$0.000882	147	\$0.000882	147
28	Energy Waste Reduction	166,773	MWh	\$0.002552	426	\$0.002552	426
29	LIEAF	21,200	cust	\$0.88	224	\$0.88	224
30	Distribution Surcharges	166,773	MWh	0.57¢	954	0.57¢	954
31							
32	Total Full Service Distribution			9.90¢	16,514	11.22¢	18,706
33	Total Full Service D1.8	166,773	MWh	17.56¢	29,279	19.31¢	32,205
34	Increase/Decrease (\$)						2,927

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Electric Vehicle Rate - D1.9

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Power Supply Charges					
2	Non-Capacity Charge	12,539 MWh				
3	On-Peak	2,063 MWh	\$0.14635	302	\$0.11700	241
4	Off-Peak	10,477 MWh	\$0.03657	383	\$0.02924	306
5	Capacity Charge					
6						
7	On-Peak	2,063 MWh	\$0.02470	51	\$0.06387	132
8	Off-Peak	10,477 MWh	\$0.00618	65	\$0.01598	167
9		12,539 MWh				
10						
11	PSCR	12,539 MWh	\$0.00000	0	\$0.00000	0
12	Total Full Service Power Supply	12,539 MWh	6.39¢	801	6.75¢	847
13						
14	Full Service Distribution	Quantity Units				
15						
16	Service Charge (\$/month)	4,978 Cust.	\$1.95	116	\$1.95	116
17						
18	Distribution Charge	12,539 MWh	\$0.08137	1,020	\$0.09451	1,185
19	Distribution System	12,539 MWh	9.07¢	1,137	10.38¢	1,302
20	IRM	12,539 MWh	\$0.000941	12	\$0.000941	12
21	Nuclear Decomm.	12,539 MWh	\$0.000882	11	\$0.000882	11
22	Energy Waste Reduction	12,539 MWh	\$0.002552	32	\$0.002552	32
23	Distribution Surcharges	12,539 MWh	0.44¢	55	0.44¢	55
24						
25	Total Full Service Distribution	12,539 MWh	9.50¢	1,192	10.82¢	1,356
26	Total Full Service D1.9	12,539 MWh	15.89¢	1,992	17.57¢	2,203
27						
28	Choice	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
29						
30	Capacity Charge					
31						
32	On-Peak	0 MWh	\$0.02470	0	\$0.06387	0
33	Off-Peak	0 MWh	\$0.00618	0	\$0.01598	0
34	Total Capacity	0 MWh		0		0
35						
36	Distribution Charges					
37	Service Charge (\$/month)	0 Cust.	\$1.95	0	\$1.95	0
38						
39	Distribution Charge	0 MWh	\$0.08137	0	\$0.09451	0
40	Distribution System	0 MWh		0		0
41	IRM	0 MWh	\$0.000941	0	\$0.000941	0
42	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
43	Energy Waste Reduction	0 MWh	\$0.002552	0	\$0.002552	0
44	Distribution Surcharges	0 MWh		0		0
45						
46	Total Choice D1.9	0 MWh		0		0
47						
48	Total D1.9	12,539 MWh	15.89¢	1,992	17.57¢	2,203
49	Increase/Decrease (\$)					211

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Standard TOU - D1.11

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present		(d)	(e) Proposed		(f)
		Quantity	Units	Rate	Revenue (\$000)		Rate	Revenue (\$000)	
	Full Service Power Supply								
1	Power Supply Charges								
2	Non-Capacity Charges								
3	June - September								
4	On Peak (3pm-7pm, M-F)	887,019	MWh	\$0.12201	108,225		\$0.09748	86,470	
5	Off Peak	4,534,773	MWh	\$0.07354	333,487		\$0.05873	266,321	
6	October - May								
7	On Peak (3pm-7pm, M-F)	1,077,809	MWh	\$0.08518	91,808		\$0.06875	74,094	
8	Off Peak	7,248,881	MWh	\$0.07354	533,083		\$0.05873	425,717	
9	Capacity Charges:								
10	June - September								
11	On Peak (3pm-7pm, M-F)	887,019	MWh	\$0.02060	18,273		\$0.05325	47,236	
12	Off Peak	4,534,773	MWh	\$0.01241	56,277		\$0.03208	145,484	
13	October - May								
14	On Peak (3pm-7pm, M-F)	1,077,809	MWh	\$0.01438	15,499		\$0.03755	40,476	
15	Off Peak	7,248,881	MWh	\$0.01241	89,959		\$0.03208	232,558	
16									
17	Power Supply Subtotal	13,748,482	MWh	9.07¢	1,246,609		9.59¢	1,318,355	
18									
19	PSCR	13,748,482	MWh	\$0.00000	0		\$0.00000	0	
20	REPS	1,968,733	Meters	\$0.00000	0		\$0.00000	0	
21	Total Full Service Power Supply	13,748,482	MWh	9.07¢	1,246,609		9.59¢	1,318,355	
22									
23	Full Service Distribution	Quantity	Units						
24									
25	Service Charge	1,968,733	Cust.	\$8.50	200,811		\$8.50	200,811	
26	Income Assistance	80,064	Cust.	(\$8.50)	(8,167)		(\$8.50)	(8,167)	
27	Senior Citizen Provision	102,050	Cust.	(\$4.25)	(5,205)		(\$4.25)	(5,205)	
28									
29	Distribution Charge	13,748,482	MWh	\$0.08137	1,118,714		\$0.09451	1,299,413	
30	Distribution System	13,748,482	MWh	9.50¢	1,306,154		10.81¢	1,486,853	
31	IRM	13,748,482	MWh	\$0.000941	12,937		\$0.000941	12,937	
32	Nuclear Decomm.	13,748,482	MWh	\$0.000882	12,126		\$0.000882	12,126	
33	Energy Waste Reduction	13,748,482	MWh	\$0.002552	35,086		\$0.002552	35,086	
34	LIEAF	1,968,733	Cust.	\$0.88	20,790		\$0.88	20,790	
35	Distribution Surcharges	13,748,482	MWh	0.59¢	80,939		0.59¢	80,939	
36									
37	Total Full Service Distribution			10.09¢	1,387,093		11.40¢	1,567,792	
38	Total Full Service D1.11	13,748,482	MWh	19.16¢	2,633,702		20.99¢	2,886,147	
39									
40	Choice	Quantity	Units	Rate	Revenue (\$000)		Rate	Revenue (\$000)	
41									
42	Capacity Charges:								
43	June - September								
44	On Peak (3pm-7pm, M-F)	0	MWH	\$0.02060	0		\$0.05325	0	
45	Off Peak	0	MWH	\$0.01241	0		\$0.03208		
46	October - May								
47	On Peak (3pm-7pm, M-F)	0	MWH	\$0.01438	0		\$0.03755	0	
48	Off Peak	0	MWH	\$0.01241	0		\$0.03208	0	
49									
50	Capacity Total	0	MWh		0			0	
51									
52	Distribution Charges								
53	Service Charge	0	Cust.	\$8.50	0		\$8.50	0	
54	Income Assistance	0	Cust.	(\$8.50)	0		(\$8.50)	0	
55	Senior Citizen Provision	0	Cust.	(\$4.25)	0		(\$4.25)	0	
56									
57	Distribution Charge	0	MWh	\$0.08137	0		\$0.09451	0	
58	Distribution System	0	MWh		0			0	
59	IRM	0	MWh	0.000941	0		0.000941	0	
60	Nuclear Decomm.	0	MWh	\$0.000882	0		\$0.000882	0	
61	Energy Waste Reduction	0	MWh	\$0.002552	0		\$0.002552	0	
62	LIEAF	0	Cust.	\$0.88	0		\$0.88	0	
63	Distribution Surcharges	0	MWh		0			0	
64									
65	Total Choice D1.11	0	MWh		0			0	
66									
67	Total D1.11	13,748,482	MWh	19.16¢	2,633,702		20.99¢	2,886,147	
68	Increase/Decrease (\$)							252,445	

Line No.	(a) Description	(b) Billing Determinants		(c) Proposed D1.11 Rates	(d) Rate	(d) Revenue (\$000)	(e) Revenue Neutral Design	(f) Rate	(f) Revenue (\$000)
	Full Service Power Supply	<u>Quantity</u>	<u>Units</u>						
1	Power Supply Charges								
2	Non-Capacity Charge								
3	June - September								
4	On Peak (3pm-7pm, M-F)	881,337	MWh				\$0.10846	95,590	
5	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	3,561,782	MWh				\$0.07298	259,947	
6	Super Off Peak (1am-7am)	978,673	MWh				\$0.04609	45,111	
7	October - May								
8	On Peak (3pm-7pm, M-F)	1,067,922	MWh				\$0.06186	66,066	
9	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	5,439,585	MWh				\$0.05552	302,032	
10	Super Off Peak (1am-7am)	1,819,184	MWh				\$0.04609	83,854	
11	Capacity Charges:								
12	June - September								
13	On Peak (3pm-7pm, M-F)	881,337	MWh				\$0.05925	52,218	
14	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	3,561,782	MWh				\$0.03987	142,002	
15	Super Off Peak (1am-7am)	978,673	MWh				\$0.02518	24,643	
16	October - May								
17	On Peak (3pm-7pm, M-F)	1,067,922	MWh				\$0.03379	36,090	
18	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	5,439,585	MWh				\$0.03033	164,992	
19	Super Off Peak (1am-7am)	1,819,184	MWh				\$0.02518	45,807	
20	Power Supply Subtotal	13,748,482	MWh		9.59¢	1,318,355		1,318,355	
21									
22	PSCR	13,748,482	MWh		\$0.00000	0	\$0.00000	0	
23	REPS	1,968,733	Meters		\$0.00000	0	\$0.00000	0	
24	Total Full Service Power Supply	13,748,482	MWh		9.59¢	1,318,355		9.59¢	1,318,355
25									
26	Full Service Distribution	<u>Quantity</u>	<u>Units</u>						
27									
28	Service Charge	1,968,733	Cust.				\$8.50	200,811	
29	Income Assistance	80,064	Cust.				(\$8.50)	(8,167)	
30	Senior Citizen Provision	102,050	Cust.				(\$4.25)	(5,205)	
31									
32									
33									
34	Distribution Charge	13,748,482	MWh						
35	June - September								
36	On Peak (3pm-7pm, M-F)	881,337	MWh				\$0.19036	167,775	
37	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	3,561,782	MWh				\$0.14277	508,526	
38	Super Off Peak (1am-7am)	978,673	MWh				\$0.04759	46,576	
39	October - May								
40	On Peak (3pm-7pm, M-F)	1,067,922	MWh				\$0.09518	101,647	
41	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	5,439,585	MWh				\$0.07139	388,313	
42	Super Off Peak (1am-7am)	1,819,184	MWh				\$0.04759	86,577	
43	Distribution System	13,748,482	MWh		10.81¢	1,486,853		10.81¢	1,486,853
44	IRM	13,748,482	MWh		\$0.000941	12,937	\$0.000941	12,937	
45	Nuclear Decomm.	13,748,482	MWh		\$0.000882	12,126	\$0.000882	12,126	
46	Energy Waste Reduction	13,748,482	MWh		\$0.002552	35,086	\$0.002552	35,086	
47	LIEAF	1,968,733	Cust.		\$0.88	20,790	\$0.88	20,790	
48	Distribution Surcharges	13,748,482	MWh		0.59¢	80,939		0.59¢	80,939
49									
50	Total Full Service Distribution				11.40¢	1,567,792		11.40¢	1,567,792
51	Total Full Service D1.13	13,748,482	MWh		20.99¢	2,886,147		20.99¢	2,886,147
52									
53	Choice	<u>Quantity</u>	<u>Units</u>		<u>Rate</u>	<u>Revenue (\$000)</u>		<u>Rate</u>	<u>Revenue (\$000)</u>
54									
55	Capacity Charges:								
56	June - September								
57	On Peak (3pm-7pm, M-F)	0	MWH				\$0.05925	0	
58	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH				\$0.03987	0	
59	Super Off Peak (1am-7am)	0	MWH				\$0.02518	0	
60	October - May								
61	On Peak (3pm-7pm, M-F)	0	MWH				\$0.03379	0	
62	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH				\$0.03033	0	
63	Super Off Peak (1am-7am)	0	MWH				\$0.02518	0	
64	Capacity Total	0	MWh			0			0
65									
66	Distribution Charges								
67	Service Charge	0	Cust.			0	\$8.50	0	
68	Income Assistance	0	Cust.			0	(\$8.50)	0	
69	Senior Citizen Provision	0	Cust.			0	(\$4.25)	0	
70									
71	Distribution Charge								
72	June - September								
73	On Peak (3pm-7pm, M-F)	0	MWH				\$0.19036	0	
74	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH				\$0.14277	0	
75	Super Off Peak (1am-7am)	0	MWH				\$0.04759	0	
76	October - May								
77	On Peak (3pm-7pm, M-F)	0	MWH				\$0.09518	0	
78	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH				\$0.07139	0	
79	Super Off Peak (1am-7am)	0	MWh			0	\$0.04759	0	
80	Distribution System	0	MWh			0			0
81	IRM	0	MWh		\$0.000941	0	\$0.000941	0	
82	Nuclear Decomm.	0	MWh		\$0.000882	0	\$0.000882	0	
83	Energy Waste Reduction	0	MWh		\$0.002552	0	\$0.002552	0	
84	LIEAF	0	Cust.		\$0.88	0	\$0.88	0	
85	Distribution Surcharges	0	MWh			0			0
86									
87	Total Choice D1.13	0	MWh			0			0
88									
89	Total D1.13	13,748,482	MWh		20.99¢	2,886,147		20.99¢	2,886,147

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Space Heating Rate - D2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	282,672	MWh	\$0.06274	17,735	\$0.05498	15,542
3	Capacity Charges						
4	Summer						
5	First 17 KWH/Day	56,257	MWh	\$0.01059	596	\$0.02817	1,585
6	Excess	29,544	MWh	\$0.01514	447	\$0.04027	1,190
7	Winter						
8	First 20 KWH/Day	102,530	MWh	\$0.00624	640	\$0.01660	1,702
9	Excess	94,341	MWh	\$0.00244	230	\$0.00649	612
10							
11	PSCR	282,672	MWh	\$0.00000	0	\$0.00000	0
12	REPS	29,878	Meters	\$0.00000	0	\$0.00000	0
13	Total Full Service Power Supply	282,672	MWh	6.95¢	19,648	7.30¢	20,630
14							
15	Full Service Distribution	Quantity	Units				
16							
17	Service Charge	29,878	Cust.	\$8.50	3,048	\$8.50	3,048
18	Income Assistance	1,228	Cust.	(\$8.50)	(125)	(\$8.50)	(125)
19	Senior Citizen Provision	774	Cust.	(\$4.25)	(39)	(\$4.25)	(39)
20							
21	Distribution Charge						
22	Summer	85,801	MWh	\$0.08137	6,982	\$0.09451	8,109
23	Winter	196,871	MWh	\$0.08137	16,019	\$0.09451	18,607
24	Distribution System	282,672	MWh	9.16¢	25,884	10.47¢	29,599
25	IRM	282,672	MWh	\$0.000941	266	\$0.000941	266
26	Nuclear Decomm.	282,672	MWh	\$0.000882	249	\$0.000882	249
27	Energy Waste Reduction	282,672	MWh	\$0.002552	721	\$0.002552	721
28	LIEAF	29,878	Cust.	\$0.88	316	\$0.88	316
29	Distribution Surcharges	282,672	MWh	0.55¢	1,552	0.55¢	1,552
30							
31	Total Full Service Distribution	282,672	MWh	9.71¢	27,436	11.02¢	31,151
32	Total Full Service D2	282,672	MWh	16.66¢	47,084	18.32¢	51,782
33							
34	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
35							
36	Capacity Charges						
37	Summer						
38	First 17 KWH/Day	0	MWh	\$0.01059	0	\$0.02817	0
39	Excess	0	MWh	\$0.01514	0	\$0.04027	0
40	Winter						
41	First 20 KWH/Day	0	MWh	\$0.00624	0	\$0.01660	0
42	Excess	0	MWh	\$0.00244	0	\$0.00649	0
43	Total Capacity				0		0
44							
45	Distribution Charges						
46	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
47	Income Assistance	0	Cust.	(\$8.50)	0	(\$8.50)	0
48	Senior Citizen Provision		Cust.	(\$4.25)	0	(\$4.25)	0
49							
50	Distribution Charge						
51	Summer	0	MWh	\$0.08137	0	\$0.09451	0
52	Winter	0	MWh	\$0.08137	0	\$0.09451	0
53	Distribution System	0	MWh		0		0
54	IRM	0	MWh	\$0.000941	0	\$0.000941	0
55	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
56	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
57	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
58	Distribution Surcharges	0	MWh		0		0
59							
60	Total Choice D2	0	MWh		0		0
61							
62	Total D2	282,672	MWh	16.66¢	47,084	18.32¢	51,782
63	Increase/Decrease (\$)						4,698

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Water Heating Service Rate - Residential D5

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Non-Capacity Charge	97,669 MWh	\$0.04132	4,036	\$0.03303	3,226
2	Capacity Charge	97,669 MWh	\$0.00698	682	\$0.01805	1,763
3						
4	PSCR	97,669 MWh	\$0.00000	0	\$0.00000	0
5	Total Full Service Power Supply	97,669 MWh	4.83¢	4,717	5.11¢	4,989
6						
7	Full-Service Distribution	Quantity Units				
8						
9	Service Charge	45,020 Cust.	\$1.95	1,053	\$1.95	1,053
10						
11	Distribution Charge	97,669 MWh	\$0.08137	7,947	\$0.09451	9,231
12	Distribution System	97,669 MWh	9.22¢	9,001	10.53¢	10,285
13	IRM	97,669 MWh	\$0.000941	92	\$0.000941	92
14	Nuclear Decomm.	97,669 MWh	\$0.000882	86	\$0.000882	86
15	Energy Waste Reduction	97,669 MWh	\$0.002552	249	\$0.002552	249
16	Distribution Surcharges	97,669 MWh	0.44¢	427	0.44¢	427
17						
18	Total Full Service Distribution	97,669 MWh	9.65¢	9,428	10.97¢	10,712
19	Total Full Service D5	97,669 MWh	14.48¢	14,146	16.08¢	15,701
20						
21	Choice	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
22						
23	Capacity Charge	0 MWh	\$0.00698	0	\$0.01805	0
24	Total Capacity	0		0		0
25						
26	Distribution Charges					
27	Service Charge	0 Cust.	\$1.95	0	\$1.95	0
28						
29	Distribution Charge	0 MWh	\$0.08137	0	\$0.09451	0
30	Distribution System	0		0		0
31	IRM	0 MWh	\$0.000941	0	\$0.000941	0
32	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
33	Energy Waste Reduction	0 MWh	\$0.002552	0	\$0.002552	0
34	Distribution Surcharges	0 MWh		0		0
35						
36	Total Choice Distribution D5	0 MWh		0		0
37						
38	Total D5	97,669 MWh	14.48¢	14,146	16.08¢	15,701
39	Increase/Decrease (\$)					1,555

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Space Conditioning Service Rate - Commercial D1.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy					
3	Summer	3,490 MWh	\$0.01049	37	\$0.02713	95
4	Winter	1,662 MWh	\$0.00470	8	\$0.01215	20
5	Non-capacity energy	5,153	\$0.06077	313	\$0.05025	259
6	Power Supply Subtotal	5,153 MWh		358		374
7						
8	PSCR	5,153 MWh	\$0.00000	0	\$0.00000	0
9	REPS	800 Meters	\$0.00	0	\$0.00	0
10	Total Full Service Power Supply	5,153 MWh		6.94¢ 358		7.26¢ 374
11						
12	Full Service Distribution					
13						
14	Service Charge (June-Oct)	800 Cust.	\$1.95	8	\$1.95	8
15						
16	Distribution Charge	5,153 MWh	\$0.05288	272	\$0.06156	317
17	Distribution System	5,153 MWh	5.44¢	280	6.31¢	325
18	IRM	5,153 MWh	\$0.000595	3	\$0.000595	3
19	Nuclear Decomm.	5,153 MWh	\$0.000882	5	\$0.000882	5
20	Energy Waste Reduction	800 Meters	\$5.50	53	\$5.50	53
21	LIEAF	800 Meters	\$0.88	8	\$0.88	8
22	Distribution Surcharges	5,153 MWh	1.34¢	69	1.34¢	69
23						
24	Total Distribution	5,153 MWh		6.78¢ 349		7.64¢ 394
25	Total Full Service D1.1	5,153 MWh		13.71¢ 707		14.90¢ 768
26						
27	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
28						
29	Capacity					
30	Energy					
31	Summer	0 MWh	\$0.01049	0	\$0.02713	0
32	Winter	0 MWh	\$0.00470	0	\$0.01215	0
33						
34	Service Charge (June-Oct)	8 Cust.	\$1.95	0	\$1.95	0
35						
36	Distribution Charge	11 MWh	\$0.05288	1	\$0.06156	1
37	Distribution System	11 MWh	5.99¢	1	6.86¢	1
38	IRM	11 MWh	0.000595	0	0.000595	0
39	Nuclear Decomm.	11 MWh	\$0.000882	0	\$0.000882	0
40	Energy Waste Reduction	8 Meters	\$5.50	1	\$5.50	1
41	LIEAF	8 Meters	\$0.88	0	\$0.88	0
42	Distribution Surcharges	11 MWh	5.64¢	1	5.64¢	1
43						
44	Total Choice D1.1	11 MWh		11.62¢ 1		12.49¢ 1
45						
46	Total D1.1	5,164 MWh		13.71¢ 708		14.89¢ 769
47	Increase/Decrease (\$)					61

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Commercial Geothermal Time of Day (D1.7)

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue	(e) Proposed	(f) Revenue
	Full Service Power Supply	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
	Capacity Charges				(\$000)		(\$000)
1	<u>Energy</u>						
2	Summer (11 a.m. Peak Start)						
3	On-Peak	1,258	MWh	\$0.00893	11	\$0.01591	20
4	Off-Peak	2,843	MWh	\$0.00464	13	\$0.01453	41
5	Winter (11 a.m. Peak Start)						
6	On-Peak	2,799	MWh	\$0.00572	16	\$0.01488	42
7	Off-Peak	8,489	MWh	\$0.00572	49	\$0.01488	126
8							
9	Non-Capacity Energy	15,388	MWh	\$0.04059	625		
10	Summer (11 a.m. Peak Start)						
11	On-Peak	1,258	MWh			\$0.03586	45
12	Off-Peak	2,843	MWh			\$0.03276	93
13	Winter (11 a.m. Peak Start)						
14	On-Peak	2,799	MWh			\$0.03354	94
15	Off-Peak	8,489	MWh			\$0.03354	285
16	Power Supply Subtotal	15,388	MWh		714		746
17							
18	PSCR	15,388	MWh	\$0.00000	0	\$0.00000	0
19	REPS	198	Meters	\$0.00	0	\$0.00	0
20	Total Full Service Power Supply	15,388	MWh		4.64¢ 714		4.85¢ 746
21							
22	Full Service Distribution	<u>Quantity</u>	<u>Units</u>				
23							
24	Service Charge	198	Cust.	\$0.067	5	\$0.067	5
25							
26	Distribution Charge	15,388	MWh	\$0.05288	814	\$0.06156	947
27	Distribution System	15,388	MWh		5.32¢ 819		6.19¢ 952
28	IRM	15,388	MWh	\$0.000595	9	\$0.000595	9
29	Nuclear Decomm.	15,388	MWh	\$0.000882	14	\$0.000882	14
30	Energy Waste Reduction	198	Meters	\$5.50	13	\$5.50	13
31	LIEAF	198	Meters	\$0.88	2	\$0.88	2
32	Distribution Surcharges	15,388	MWh		0.25¢ 38		0.25¢ 38
33							
34	Total Distribution	15,388	MWh		5.57¢ 856		6.43¢ 990
35	Total Full Service D1.7	15,388	MWh		10.20¢ 1,570		11.28¢ 1,736
36							
37	Choice Distribution	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>	<u>Revenue</u>	<u>Rate</u>	<u>Revenue</u>
38					(\$000)		(\$000)
39	Capacity Charges						
40	<u>Energy</u>						
41	Summer (11 a.m. Peak Start)						
42	On-Peak		MWh	\$0.00893	0	\$0.01591	0
43	Off-Peak		MWh	\$0.00464	0	\$0.01453	0
44	Winter (11 a.m. Peak Start)						
45	On-Peak		MWh	\$0.00572	0	\$0.01488	0
46	Off-Peak		MWh	\$0.00572	0	\$0.01488	0
47							
48	Service Charge	1	Cust.	\$0.067	0	\$0.067	0
49							
50	Distribution Charge	198	MWh	\$0.05288	10	\$0.06156	12
51	Distribution System	198	MWh		5.30¢ 11		6.17¢ 12
52	IRM	198	MWh	\$0.000595	0	\$0.000595	0
53	Nuclear Decomm.	198	MWh	\$0.000882	0	\$0.000882	0
54	Energy Waste Reduction	1	Meters	\$5.50	0	\$5.50	0
55	LIEAF	1	Meters	\$0.88	0	\$0.88	0
56	Distribution Surcharges	198	MWh		0.19¢ 0		0.19¢ 0
57							
58	Total Choice D1.7	198	MWh		5.49¢ 11		6.35¢ 13
59							
60	Total D1.7	15,586	MWh		10.14¢ 1,581		11.22¢ 1,749
61	Increase/Decrease (\$)						168

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Commercial Dynamic Peak Pricing Rate - D1.8

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
	Capacity					
1	Energy					
2	Off-Peak (11pm-7am)	460 MWh	\$0.00570	3	\$0.01457	7
3	Mid-Peak (7 pm-11pm, 7am-3pm)	387 MWh	\$0.01119	4	\$0.02862	11
4	On-Peak (3 pm- 7 pm)	125 MWh	\$0.02062	3	\$0.05271	7
5	Critical Peak (3pm-7pm)	0 MWh	\$0.80517	0	\$0.82837	0
6						
7	Non-capacity energy	972 MWh				
8	Off-Peak (11pm-7am)	460 MWh	\$0.04002	18	\$0.03311	15
9	Mid-Peak (7 pm-11pm, 7am-3pm)	387 MWh	\$0.07863	30	\$0.06505	25
10	On-Peak (3 pm- 7 pm)	125 MWh	\$0.14483	18	\$0.12163	15
11	Critical Peak (3pm-7pm)	0 MWh	\$0.14483	0	\$0.12163	0
12	Power Supply Subtotal	972 MWh		77		80
13						
14	PSCR	972 MWh	\$0.00000	0	\$0.00000	0
15	REPS	28 Cust.	\$0.00	0	\$0.00	0
16	Total Full Service Power Supply	972 MWh	7.90¢	77	8.26¢	80
17						
18	Full Service Distribution	Quantity Units				
19						
20	Service Charge	28 Cust.	\$11.25	4	\$11.25	4
21						
22	Distribution Charge	972 MWh	\$0.05288	51	\$0.06156	60
23	Distribution System	972 MWh	5.68¢	55	6.55¢	64
24	IRM	972 MWh	\$0.000595	1	\$0.000595	1
25	Nuclear Decomm.	972 MWh	\$0.000882	1	\$0.000882	1
26	Energy Waste Reduction	28 Cust.	\$5.50	2	\$5.50	2
27	LIEAF	28	\$0.88	0	\$0.88	0
28	Distribution Surcharges	972 MWh	0.37¢	4	0.37¢	4
29	Total Full Service D1.1					
30	Total Full Service Distribution	972 MWh	6.04¢	59	6.91¢	67
31	Total Full Service D1.8	972 MWh	13.94¢	136	15.17¢	148
32	Increase/Decrease (\$)					12

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Commercial Electric Vehicle Rate - D1.9

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Revenue (\$000)	(e) Proposed	(f) Revenue (\$000)
	Full Service Power Supply	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Power Supply Charges					
2	Capacity					
3	Option I					
4	On-Peak	105 MWh	\$0.02470	3	\$0.06387	7
5	Off-Peak	237 MWh	\$0.00618	1	\$0.01598	4
6		342 MWh				
7						
8	Non-capacity energy charge					
	On-Peak	105 MWh	\$0.14635	15	\$0.11700	12
	Off-Peak	237 MWh	\$0.03657	9	\$0.02924	7
9						
10	PSCR	342 MWh	\$0.00000	0	\$0.00000	0
11						
12						
13	Total Full Service Power Supply	342 MWh	8.20¢	28	8.67¢	30
14						
15	Full Service Distribution					
16						
17	Option I Service Charge (\$/month)	22 Cust.	\$1.95	1	\$1.95	1
18						
19	Distribution Charge	342 MWh	\$0.08137	28	\$0.09451	32
20	Distribution System	342 MWh	8.29¢	28	9.60¢	33
21	IRM	342 MWh	\$0.000595	0	\$0.000595	0
22	Nuclear Decomm.	342 MWh	\$0.000882	0	\$0.000882	0
23	Energy Waste Reduction	22 Meters	\$5.50	1	\$5.50	1
24	LIEAF	342 Meters	\$0.88	4	\$0.88	4
25	Distribution Surcharges	342 MWh	1.63¢	6	1.63¢	6
26						
27	Total Full Service Distribution	342 MWh	9.92¢	34	11.23¢	38
28	Total Full-Service D1.9	342 MWh	18.12¢	62	19.90¢	68
29						
30	Choice Distribution					
31						
32	Capacity					
33	Option I					
34	On-Peak	0 MWh	\$0.02470	0	\$0.06387	0
35	Off-Peak	0 MWh	\$0.00618	0	\$0.01598	0
36		0 MWh				
37	Option I Service Charge (\$/month)	0 Cust.	\$1.95	0	\$1.95	0
38						
39	Distribution Charge	0 MWh	\$0.08137	0	\$0.09451	0
40	Distribution System	0 MWh	0	0	0	0
41	IRM	0 MWh	\$0.000595	0	\$0.000595	0
42	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
43	Energy Waste Reduction	0 Meters	\$5.50	0	\$5.50	0
44	LIEAF	0 Meters	\$0.880000	0	\$0.880000	0
45	Distribution Subtotal	0 MWh	0	0	0	0
46						
47						
48	Total Choice D1.9	0 MWh	0	0	0	0
49						
50	Total D1.9	342 MWh	18.12¢	62	19.90¢	68
51	Increase/Decrease (\$)					6

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
General Service Rate - D3

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	7,457,882 MWh	\$0.01010	75,325	\$0.02605	194,249
3						
4	Non-Capacity					
5	Energy	7,457,882	\$0.07096	529,211	\$0.05870	437,812
6						
7	PSCR	7,457,882 MWh	\$0.00000	0	\$0.00000	0
8	REPS	197,670 Meters	\$0.00	0	\$0.00	0
9	Total Full Service Power Supply	7,457,882 MWh	8.11¢	604,536	8.48¢	632,062
10						
11	Full Service Distribution	Quantity Units				
12						
13	Service Charge	197,670 Cust.	\$11.25	26,685	\$11.25	26,685
14						
15	Distribution Charge	7,457,882 MWh	\$0.05288	394,373	\$0.06156	459,130
16	Distribution System	7,457,882 MWh	5.65¢	421,058	6.51¢	485,816
17	IRM	7,457,882 MWh	\$0.000595	4,437	\$0.000595	4,437
18	Nuclear Decomm.	7,457,882 MWh	\$0.000882	6,578	\$0.000882	6,578
19	Energy Optimization	197,670 Meters	\$5.50	13,046	\$5.50	13,046
20	LIEAF	197,670 Meters	\$0.88	2,087	\$0.88	2,087
21	Distribution Surcharges	7,457,882 MWh	0.35¢	26,149	0.35¢	26,149
22						
23	Total Full Service Distribution	7,457,882 MWh	6.00¢	447,207	6.86¢	511,965
24	Total Full Service D3	7,457,882 MWh	14.10¢	1,051,743	15.34¢	1,144,026
25						
26	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
27						
28	Capacity					
29	Energy	0 MWh	\$0.01010	0	\$0.02605	0
30						
31	Service Charge	1,843 Cust.	\$11.25	249	\$11.25	249
32						
33	Distribution Charge	261,446 MWh	\$0.05288	13,825	\$0.06156	16,095
34	Distribution System	261,446 MWh	5.38¢	14,074	6.25¢	16,344
35	IRM	261,446 MWh	\$0.000595	156	\$0.000595	156
36	Nuclear Decomm.	261,446 MWh	\$0.000882	231	\$0.000882	231
37	Energy Optimization	1,843 Meters	\$5.50	122	\$5.50	122
38	LIEAF	1,843 Meters	\$0.88	19	\$0.88	19
39	Distribution Surcharges	261,446 MWh	0.20¢	527	0.20¢	527
40						
41	Total Choice D3	261,446 MWh	5.58¢	14,601	6.45¢	16,871
42						
43	Total D3	7,719,328 MWh	13.81¢	1,066,344	15.04¢	1,160,898
44	Increase/Decrease (\$)					94,553

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Unmetered General Service Rate - D3.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Connected Load	254,666,315	Watts				
2							
3	Capacity						
4	Energy	89,133	MWh	0.00848	756	0.02214	1,973
5							
6	Non-capacity energy	89,133	MWh	0.11247	10,025	0.11146	9,934
7							
8	PSCR	89,133	MWh	0.00000	0	0	0
9	IRM	89,133	MWh	0.000595	53	0.000595	53
10	Nuclear Decommissioning	89,133	MWh	0.000882	79	0.000882	79
11							
12	Energy Waste Reduction	2,300	Meters	5.50	152	5.50	152
13							
14	REPS	2,300	Meters	0.00	0	0.00	0
15							
16	Total D3.1	89,133	MWh		11,064		12,191
	Increase/Decrease (\$)						1,127

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Secondary Educational Institute - D3.2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	331,944 MWh	\$0.00939	3,117	\$0.02426	8,053
3						
4	Non-capacity energy	331,944 MWh	\$0.06937	23,027	\$0.05764	19,133
5						
6	PSCR	331,944 MWh	\$0.00000	0	\$0.00000	0
7	REPS	1,185 Meters	\$0.00	0	\$0.00	0
8	Total Full Service Power Supply	331,944 MWh	7.88¢	26,144	8.19¢	27,186
9						
10	Full Service Distribution	Quantity Units				
11						
12	Service Charge	1,185 Cust.	\$11.25	160	\$11.25	160
13						
14	Distribution Charge	331,944 MWh	\$0.05288	17,553	\$0.06156	20,435
15	Distribution System	331,944 MWh	5.34¢	17,713	6.20¢	20,595
16	IRM	331,944 MWh	\$0.000595	198	\$0.000595	198
17	Nuclear Decomm.	331,944 MWh	\$0.000882	293	\$0.000882	293
18	Energy Waste Reduction	1,185 Meters	\$5.50	78	\$5.50	78
19	LIEAF	1,185 Meters	\$0.88	13	\$0.88	13
20	Distribution Surcharges	331,944 MWh	0.18¢	581	0.18¢	581
21						
22	Total Full Service Distribution	331,944 MWh	5.51¢	18,294	6.38¢	21,176
23	Total Full Service D3.2	331,944 MWh	13.39¢	44,438	14.57¢	48,362
24						
25	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26						
27	Capacity					
28	Energy	0 MWh	\$0.00939	0	\$0.02426	0
29						
30	Service Charge	767 Cust.	\$11.25	104	\$11.25	104
31						
32	Distribution Charge	296,801 MWh	\$0.05288	15,695	\$0.06156	18,272
33	Distribution System	296,801 MWh	5.32¢	15,798	6.19¢	18,376
34	IRM	296,801 MWh	\$0.000595	177	\$0.000595	177
35	Nuclear Decomm.	296,801 MWh	\$0.000882	262	\$0.000882	262
36	Energy Waste Reduction	767 Meters	\$5.50	51	\$5.50	51
37	LIEAF	767 Meters	\$0.88	8	\$0.88	8
38	Distribution Surcharges	296,801 MWh	0.00¢	497	0.17¢	497
39						
40	Total Choice D3.2	296,801 MWh	5.49¢	16,296	6.36¢	18,873
41						
42	Total D3.2	628,745 MWh	9.66¢	60,733	10.69¢	67,235
43	Increase/Decrease (\$)					6,501

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible General Service Rate - D3.3

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	54,552 MWh	\$0.00844	460	\$0.02176	1,187
3						
4	Non-capacity energy	54,552 MWh	\$0.05929	3,234	\$0.04905	2,676
5						
6	PSCR	54,552 MWh	\$0.00000	0	\$0.00000	0
7	REPS	64 Meters	\$0.00	0	\$0.00	0
8	Total Full Service Power Supply	54,552 MWh	6.77¢	3,695	7.08¢	3,863
9						
10	Full Service Distribution	Quantity Units				
11						
12	Service Charge	64 Cust.	\$11.25	9	\$11.25	9
13						
14	Distribution Charge	54,552 MWh	\$0.05288	2,885	\$0.06156	3,358
15	Distribution System	54,552 MWh	5.30¢	2,893	6.17¢	3,367
16	IRM	54,552 MWh	\$0.000595	32	\$0.000595	32
17	Nuclear Decomm.	54,552 MWh	\$0.000882	48	\$0.000882	48
18	Energy Waste Reduction	64 Meters	\$5.50	4	\$5.50	4
19	LIEAF	64 Meters	\$0.88	1	\$0.88	1
20	Distribution Surcharges	54,552 MWh	0.16¢	85	0.16¢	85
21						
22	Full Service Distribution	54,552 MWh	5.46¢	2,979	6.33¢	3,452
23	Total Full Service D3.3	54,552 MWh	12.23¢	6,674	13.41¢	7,316
24						
25	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26						
27	Capacity					
28	Energy	0 MWh	\$0.00844	0	\$0.02176	0
29						
30	Service Charge	4 Cust.	\$11.25	1	\$11.25	1
31						
32	Distribution Charge	7,513 MWh	\$0.05288	397	\$0.06156	463
33	Distribution System	7,513 MWh	5.30¢	398	6.16¢	463
34	IRM	7,513 MWh	0.000595	4	0.000595	4
35	Nuclear Decomm.	7,513 MWh	\$0.000882	7	\$0.000882	7
36	Energy Waste Reduction	4 Meters	\$5.50	0	\$5.50	0
37	LIEAF	4 Meters	\$0.88	0	\$0.88	0
38	Distribution Surcharges	7,513 MWh	0.15¢	11	0.15¢	11
39						
40	Total Choice D3.3	7,513 MWh	5.45¢	409	6.32¢	474
41						
42	Total D3.3	62,065 MWh	11.41¢	7,083	12.55¢	7,790
43	Increase/Decrease (\$)					707

**Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Company Owned Charging Service - D3.5**

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 21 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present		(d) Proposed	
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1							
2	Non Capacity On Peak (2pm-5pm, M-F)	0	MWh	\$0.07688	0	\$0.08038	0
3	Non Capacity Off Peak	0	MWh	\$0.06843	0	\$0.07155	0
4	PSCR	0	MWh	\$0.00000	0	\$0.00000	0
5	Session Fee						
6	< 200 kW	0	session	\$21.00	0	\$21.00	0
7	> 200 kW	0	session	\$66.00	0	\$66.00	0
8	IRM	0	MWh	0.000595	0	0.000595	0
9	Nuclear Decomm.	0	MWh	0.000882	0	0.000882	0
10	Energy Waste Reduction	0	MWh	0.000000	0	0.000000	0
11	LIEAF	0	MWh	0.000000	0	0.000000	0
12							
13							
14	Total D3.5	0	MWh		0	0.00¢	0
	Increase/Decrease (\$)						-

Michigan Public Service Commission
DTE Electric Company
Optional TOU General Service Rate - D3.11
Designed Revenue Neutral to D3

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 22 of 58
Revised

Line	(a)	(b)	(c)	(d)	(e)	(f)
No.	Description	Billing Determinants <i>Revised</i>	Proposed D3	Revenue Neutral Design <i>Revised</i>		
		<u>Quantity</u> <u>Units</u>	<u>Rate</u> <u>Revenue</u> (\$000)	<u>Rate</u> <u>Revenue</u> (\$000)		
1	Full Service Power Supply					
2	Capacity					
3	June - September					
4	On Peak (1pm - 5pm M-F)	439,913 MWh		\$0.04173 18,356		
5	Off Peak	2,300,571 MWh		\$0.02489 57,254		
6	October - May					
7	On Peak (1pm - 5pm M-F)	711,494 MWh		\$0.02663 18,947		
8	Off Peak	4,005,903 MWh		\$0.02489 99,694		
9	Non-Capacity					
10	June - September					
11	On Peak (1pm - 5pm M-F)	439,913 MWh		\$0.09404 41,371		
12	Off Peak	2,300,571 MWh		\$0.05609 129,042		
13	October - May					
14	On Peak (1pm - 5pm M-F)	711,494 MWh		\$0.06002 42,703		
15	Off Peak	4,005,903 MWh		\$0.05609 224,696		
16						
17	PSCR	7,457,882 MWh		\$0.00000 0		
18	REPS	197,670 Meters		\$0.00 0		
19	Total Full Service Power Supply	7,457,882 MWh	8.48¢ 632,062	8.48¢ 632,062		
20						
21	Full Service Distribution	<u>Quantity</u> <u>Units</u>				
22						
23	Service Charge	197,670 Cust.	\$11.25 26,685	\$11.25 26,685		
24						
25	Distribution Charge	7,457,882 MWh	\$0.06156 459,130	\$0.06156 459,130		
26	Distribution System	7,457,882 MWh	6.51¢ 485,816	6.51¢ 485,816		
27	IRM	7,457,882 MWh	\$0.000595 4,437	\$0.000595 4,437		
28	Nuclear Decomm.	7,457,882 MWh	\$0.000882 6,578	\$0.000882 6,578		
29	Energy Optimization	197,670 Meters	\$5.50 13,046	\$5.50 13,046		
30	LIEAF	197,670 Meters	\$0.88 2,087	\$0.88 2,087		
31	Distribution Surcharges	7,457,882 MWh	0.35¢ 26,149	0.35¢ 26,149		
32						
33	Total Full Service Distribution	7,457,882 MWh	6.86¢ 511,965	6.86¢ 511,965		
34	Total Full Service D3.11	7,457,882 MWh	15.34¢ 1,144,026	15.34¢ 1,144,026		
35						
36	Choice Distribution	<u>Quantity</u> <u>Units</u>	<u>Rate</u> <u>Revenue</u> (\$000)	<u>Rate</u> <u>Revenue</u> (\$000)		
37						
38	Capacity					
39	June - September					
40	On Peak (1pm - 5pm M-F)	0 MWh		\$0.04173 0		
41	Off Peak	0 MWh		\$0.02489 0		
42	October - May					
43	On Peak (1pm - 5pm M-F)	0 MWh		\$0.02663 0		
44	Off Peak	0 MWh		\$0.02489 0		
45						
46	Service Charge	1,843 Cust.	\$11.25 249	\$11.25 249		
47						
48	Distribution Charge	261,446 MWh	\$0.06156 16,095	\$0.06156 16,095		
49	Distribution System	261,446 MWh	6.25¢ 16,344	6.25¢ 16,344		
50	IRM	261,446 MWh	\$0.000595 156	\$0.000595 156		
51	Nuclear Decomm.	261,446 MWh	\$0.000882 231	\$0.000882 231		
52	Energy Optimization	1,843 Meters	\$5.50 122	\$5.50 122		
53	LIEAF	1,843 Meters	\$0.88 19	\$0.88 19		
54	Distribution Surcharges	261,446 MWh	0.20¢ 527	0.20¢ 527		
55						
56	Total Choice D3.11	261,446 MWh	6.45¢ 16,871	6.45¢ 16,871		
57						
58	Total D3.11	7,719,328 MWh	15.04¢ 1,160,898	15.04¢ 1,160,898		
59	Increase/Decrease (\$)					-

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Large General Service Rate - D4

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue	(e) Proposed	(f) Revenue
		Quantity	Units	Rate	((\$000))	Rate	((\$000))
	Full Service Power Supply						
1	Capacity						
2	Demand Charge	4,219,890	kW	\$3.57	15,065	\$9.18	38,720
3	Energy						
4	First 200 Hrs. Use	853,413	MWh	\$0.00000	0	\$0.00000	0
5	Excess	885,101	MWh	\$0.00000	0	\$0.00000	0
6	Power Supply Subtotal	1,738,514	MWh		15,065		38,720
7							
8	Non-capacity						
9	Demand Charge	4,219,890	kW	13.02	54,943	\$8.07	34,036
10	Energy						
11	First 200 Hrs. Use	853,413	MWh	0.04012	34,239	\$0.04169	35,583
12	Excess	885,101	MWh	0.03097	27,412	\$0.03219	28,488
13	PSCR	1,738,514	MWh	\$0.00000	0	\$0.00000	0
14	REPS	7,791	Meters	\$0.00	0	\$0.00	0
15	Total Full Service Power Supply	1,738,514	MWh	7.57¢	131,658	7.87¢	136,827
16							
17	Full Service Distribution	Quantity	Units				
18							
19	Service Charge	7,791	Cust.	\$13.67	1,278	\$13.67	1,278
20							
21	Distribution Demand Charge	4,219,890	kW	\$21.80	91,994	\$25.21	106,380
22	Distribution Energy Charge	1,738,514	MWh	\$0.000000	0	\$0.000000	0
23	Distribution Charges	1,738,514	MWh	5.37¢	93,272	6.19¢	107,658
24	IRM	4,219,890	kW	\$0.2454	1,036	\$0.2454	1,036
25	Nuclear Decomm.	1,738,514	MWh	\$0.000882	1,533	\$0.000882	1,533
26	Energy Waste Reduction	7,791	Meters	\$140.21	13,109	\$140.21	13,109
27	LIEAF	7,791	Meters	\$0.88	82	\$0.88	82
28	Distribution Surcharges	1,738,514	MWh	0.91¢	15,760	0.91¢	15,760
29							
30	Total Full Service Distribution	1,738,514	MWh	6.27¢	109,031	7.10¢	123,418
31	Total Full Service D4	1,738,514	MWh	13.84¢	240,690	14.97¢	260,244
32							
33	Choice Distribution	Quantity	Units	Rate	Revenue	Rate	Revenue
34					((\$000))		((\$000))
35	Capacity						
36	Demand Charge	0	kW	\$3.57	0	\$9.18	0
37	Energy						
38	First 200 Hrs. Use	0	MWh	\$0.00000	0	\$0.00000	0
39	Excess	0	MWh	\$0.00000	0	\$0.00000	0
40							
41	Service Charge	773	Cust.	\$13.67	127	\$13.67	127
42							
43	Distribution Demand Charge	647,797	kW	\$21.80	14,122	\$25.21	16,330
44	Distribution Energy Charge	254,735	MWh	\$0.00000	0	\$0.00000	0
45	Distribution System	254,735	MWh	5.59¢	14,249	6.46¢	16,457
46	IRM	647,797	kW	\$0.2454	159	\$0.2454	159
47	Nuclear Decomm.	254,735	MWh	\$0.000882	225	\$0.000882	225
48	Energy Waste Reduction	773	Meters	\$140.21	1,301	\$140.21	1,301
49	LIEAF	773	Meters	\$0.88	8	\$0.88	8
50	Distribution Surcharges	254,735	MWh	0.66¢	1,692	0.66¢	1,692
51							
52	Total Choice D4	254,735	MWh	6.26¢	15,941	7.12¢	18,150
53							
54	Total D4	1,993,249	MWh	12.88¢	256,631	13.97¢	278,394
55	Increase/Decrease (\$)						21,763

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Water Heating Service Rate - Commercial D5

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	9,881 MWh	\$0.00595	59	\$0.01534	152
3						
4	Non-capacity energy	9,881 MWh	\$0.04178	413	\$0.03457	342
5						
6	PSCR	9,881 MWh	\$0.00000	0	\$0.00000	0
7	REPS	764 Meters	\$0.00	0	\$0.00	0
8	Total Full Service Power Supply	9,881 MWh	4.77¢	472	4.99¢	493
9						
10	Full Service Distribution	Quantity Units				
11						
12	Service Charge	764 Cust.	\$1.95	18	\$1.95	18
13						
14	Distribution Charge	9,881 MWh	\$0.05288	523	\$0.06156	608
15	Distribution System	9,881 MWh	5.47¢	540	6.34¢	626
16	IRM	9,881 MWh	\$0.000595	6	\$0.000595	6
17	Nuclear Decomm.	9,881 MWh	\$0.000882	9	\$0.000882	9
18	Energy Waste Reduction	764 Meters	\$5.50	50	\$5.50	50
19	LIEAF	764 Meters	\$0.88	8	\$0.88	8
20	Distribution Surcharges	9,881 MWh	0.74¢	73	0.74¢	73
21						
22	Total Full Service Distribution	9,881 MWh	6.21¢	613	7.08¢	699
23	Total Full Service D5	9,881 MWh	10.98¢	1,085	12.07¢	1,192
24						
25	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26						
27	Capacity					
28	Energy	0 MWh	\$0.00595	0	\$0.01534	0
29						
30	Service Charge	1 Cust.	\$1.95	0	\$1.95	0
31						
32	Distribution Charge	4 MWh	\$0.05288	0	\$0.06156	0
33	Distribution System	4 MWh	5.81¢	0	6.68¢	0
34	IRM	4 MWh	\$0.000595	0	\$0.000595	0
35	Nuclear Decomm.	4 MWh	\$0.000882	0	\$0.000882	0
36	Energy Waste Reduction	1 Meters	\$5.50	0	\$5.50	0
37	LIEAF	1 Meters	\$0.88	0	\$0.88	0
38	Distribution Surcharges	4 MWh	1.87¢	0	1.87¢	0
39						
40	Total Choice D5	4 MWh	7.69¢	0	8.55¢	0
41						
42	Total D5	9,886 MWh	10.98¢	1,085	12.07¢	1,193
43	Increase/Decrease (\$)					107

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Energy Only Street Lighting E1.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 25 of 58

Line No.	(a) Description	(b) Billing Determinants Quantity Units	(c) Present Rate	(d) Revenue (\$000)	(e) Proposed Rate	(f) Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy					
3	Secondary	10,251 MWh	\$0.00692	71	\$0.01792	184
4	Dusk to Midnight	4 MWh	\$0.03023	0	\$0.07829	0
5	Primary Energy	0 MWh	\$0.00692	0	\$0.01792	0
6						
7	Non-capacity charge	10,256	\$0.04892	502	\$0.04045	415
8	Power Supply Subtotal	10,256 MWh	5.58¢	573	5.84¢	599
9						
10	PSCR	10,256 MWh	\$0.00000	0	\$0.00000	0
11	REPS	279 Meters	\$0.00	0	\$0.00	0
12	Total Full Service Power Supply	10,256 MWh	5.58¢	573	5.84¢	599
13						
14	Full Service Distribution					
15						
16	Distribution Charge	10,256 MWh	\$0.05288	542	\$0.06156	631
17	Distribution System	10,256 MWh	5.29¢	542	6.16¢	631
18	IRM	10,256 MWh	\$0.000595	6	\$0.000595	6
19	Nuclear Decomm.	10,256 MWh	\$0.000882	9	\$0.000882	9
20	Energy Waste Reduction	279 Meters	\$5.50	18	\$5.50	18
21	LIEAF	279 Meters	\$0.88	3	\$0.88	3
22	Distribution Surcharges	10,256 MWh	0.36¢	36	0.36¢	36
23						
24	Total Distribution	10,256 MWh	5.64¢	579	6.51¢	668
25	Total Full Service E1.1	10,256 MWh	11.23¢	1,152	12.35¢	1,267
26						
27	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
28						
29	Capacity					
30	Energy					
31	Secondary	0 MWh	\$0.00692	0	\$0.01792	0
32	Dusk to Midnight	0 MWh	\$0.03023	0	\$0.07829	0
33	Primary Energy	0 MWh	\$0.00692	0	\$0.01792	0
34						
35	Distribution Charge	0 MWh	\$0.05288	0	\$0.06156	0
36	Distribution System	0 MWh		0		0
37	IRM	0 MWh	\$0.000595	0	\$0.000595	0
38	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
39	Energy Waste Reduction	0 Meters	\$5.50	0	\$5.50	0
40	LIEAF	0 Meters	\$0.88	0	\$0.88	0
41	Distribution Surcharges	0 MWh		0		0
42						
43	Total Choice E1.1	0 MWh		0		0
44						
45	Total E1.1	10,256 MWh	11.23¢	1,152	12.35¢	1,267
46	Increase/Decrease (\$)					115

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Greenhouse Lighting Service Rate - Standard Contract Rider No. R7

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	4,153 MWh	\$0.00577	24	\$0.01488	62
3						
4	Non-capacity					
5	Energy	4,153 MWh	\$0.04054	168	\$0.03354	139
6						
7	PSCR	4,153 MWh	\$0.00000	0	\$0.00000	0
8	REPS	9 Meters	\$0.00	0	\$0.00	0
9	Total Full Service Power Supply	4,153 MWh	4.63¢	192	4.84¢	201
10						
11	Full Service Distribution	Quantity Units				
12						
13	Service Charge	9 Cust.	\$1.95	0	\$1.95	0
14						
15	Distribution Charge	4,153 MWh	\$0.05288	220	\$0.06156	256
16	Distribution System	4,153 MWh	5.29¢	220	6.16¢	256
17	IRM	4,153 MWh	\$0.000595	2	\$0.000595	2
18	Nuclear Decomm.	4,153 MWh	\$0.000882	4	\$0.000882	4
19	Energy Waste Reduction	9 Meters	\$5.50	1	\$5.50	1
20	LIEAF	9 Meters	\$0.88	0	\$0.88	0
21	Distribution Surcharges	4,153 MWh	0.16¢	7	0.16¢	7
22						
23	Total Distribution	4,153 MWh	5.46¢	227	6.33¢	263
24	Total Full Service R7	4,153 MWh	10.09¢	419	11.17¢	464
25						
26	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
27						
28	Capacity					
29	Energy	0 MWh	\$0.00577	0	\$0.01488	0
30						
31	Service Charge	0 Cust.	\$1.95	0	\$1.95	0
32						
33	Distribution Charge	0 MWh	\$0.05288	0	\$0.06156	0
34	Distribution System	0 MWh	0	0	0	0
35	IRM	0 MWh	\$0.000595	0	\$0.000595	0
36	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
37	Energy Waste Reduction	0 Meters	\$5.50	0	\$5.50	0
38	LIEAF	0 Meters	\$0.88	0	\$0.88	0
39	Distribution Surcharges	0 MWh	0	0	0	0
40						
41	Total Choice R7	0 MWh	0	0	0	0
42						
43	Total R7	4,153 MWh	10.09¢	419	11.17¢	464
44	Increase/Decrease (\$)					45

Michigan Public Service Commission

DTE Electric Company

Present and Proposed Revenue

Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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(a)	(b)	(c)	(d)	(e)	(f)		
Description		Billing Determinants		Present		Proposed	
Full Service Power Supply	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)	
Capacity							
Energy							
Summer June-Oct							
R8 All KWH- Separate Meter	18,111	MWh	\$0.01539	279	\$0.04013	727	
R8a initial Block of D3	1,429	MWh	\$0.01010	14	\$0.02605	37	
R8a Excess	444	MWh	\$0.01539	7	\$0.04013	18	
Winter Nov-May							
R8 First 1000 KWH- Sep Mtr	5,018	MWh	\$0.01539	77	\$0.04013	201	
R8 Excess	33,771	MWh	\$0.00510	172	\$0.01330	449	
R8a initial Block of D3	2,614	MWh	\$0.01010	26	\$0.02605	68	
Excess	11,955	MWh	\$0.00510	61	\$0.01330	159	
Non-capacity Charge	73,342	MWh	\$0.06173	4,527	\$0.05099	3,740	
Power Supply Subtotal	73,342	MWh	5,164		5,399		
PSCR	73,342	MWh	\$0.00000	0	\$0.00000	0	
REPS	1,678	Meters	\$0.00	0	\$0.00	0	
Total Full Service Power Supply	73,342	MWh	7.04¢	5,164	7.36¢	5,399	
Full Service Distribution	Quantity	Units					
Service Charge							
R8 Separate Meter	1,066	Cust.	\$11.25	144	\$11.25	144	
R8a	612	Cust.	\$11.25	83	\$11.25	83	
Distribution Charge	73,342	MWh	\$0.05288	3,878	\$0.06156	4,515	
Distribution System	73,342	MWh	5.60¢	4,105	6.47¢	4,742	
IRM	73,342	MWh	\$0.000595	44	\$0.000595	44	
Nuclear Decomm.	73,342	MWh	\$0.000882	65	\$0.000882	65	
Energy Waste Reduction	1,066	Meters	\$5.50	\$70	\$5.50	70	
LIEAF	1,066	Meters	\$0.88	11	\$0.88	11	
Distribution Surcharges	73,342	MWh	0.26¢	190	0.26¢	190	
Total Distribution	73,342	MWh	5.86¢	4,295	6.72¢	4,932	
Total Full Service R8	73,342	MWh	12.90¢	9,459	14.09¢	10,331	
Choice Distribution	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)	
Capacity							
Energy							
R8 All KWH- Separate Meter	0	MWh	\$0.01539	0	\$0.04013	0	
R8a initial Block of D3	0	MWh	\$0.01010	0	\$0.02605	0	
R8a Excess	0	MWh	\$0.01539	0	\$0.04013	0	
Winter Nov-May							
R8 First 1000 KWH- Sep Mtr	0	MWh	\$0.01539	0	\$0.04013	0	
R8 Excess	0	MWh	\$0.00510	0	\$0.01330	0	
R8a initial Block of D3	0	MWh	\$0.01010	0	\$0.02605	0	
Excess	0	MWh	\$0.00510	0	\$0.01330	0	
Service Charge							
R8 Separate Meter	14	Cust.	\$11.25	2	\$11.25	2	
R8a	0	Cust.	\$11.25	0	\$11.25	0	
Distribution Charge	1,371	MWh	\$0.05288	73	\$0.06156	84	
Distribution System	1,371	MWh	5.43¢	74	6.29¢	86	
IRM	1,371	MWh	\$0.000595	1	\$0.000595	1	
Nuclear Decomm.	1,371	MWh	\$0.000882	1	\$0.000882	1	
Energy Waste Reduction	14	Meters	\$5.50	1	\$5.50	1	
LIEAF	14	Meters	\$0.88	0	\$0.88	0	
Distribution Surcharges	1,371	MWh	0.23¢	3	0.23¢	3	
Total Choice R8	1,371	MWh	5.65¢	78	6.52¢	89	
Total R8	74,713	MWh	12.76¢	9,537	13.95¢	10,420	
Increase/Decrease (\$)				884			

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Supply Rate - D11
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Power Supply Demand	21,460,521	kW	3.56	76,399	9.19	197,118
2	<u>Voltage Level Discount</u>						
3	Subtransmission	2,259,951	kW	(0.07)	(158)	(0.19)	(422)
4	Transmission	6,643,543	kW	(0.15)	(997)	(0.39)	(2,573)
5							
6	<u>Energy</u>						
7	On-Peak	2,894,545	MWh		0		0
8	Off-Peak	8,610,839	MWh		0		0
9	Total Energy	11,505,383	MWh				
10							
11	<u>Voltage Level Discount</u>						
12	Subtransmission	1,298,106	MWh	0.00000	0	0.00000	0
13	Transmission	4,354,860	MWh	0.00000	0	0.00000	0
14	Total Capacity	11,505,383	MWh		75,245		194,124
15							
16	Non-Capacity						
17	Power Supply Demand	21,460,521	kW	13.33	286,069	8.35	179,159
18	<u>Voltage Level Adjustment</u>						
19	Subtransmission	2,259,951	kW	(0.24)	(542)	(0.17)	(383)
20	Transmission	6,643,543	kW	(0.53)	(3,521)	(0.35)	(2,338)
21	<u>Energy</u>						
22	On-Peak	2,894,545	MWh	0.04257	123,221	0.04388	127,015
23	Off-Peak	8,610,839	MWh	0.03257	280,455	0.03388	291,744
24	<u>Voltage Level Discount</u>						
25	Subtransmission	1,298,106	MWh	(0.00062)	(805)	(0.00064)	(836)
26	Transmission	4,354,860	MWh	(0.00138)	(6,010)	(0.00143)	(6,245)
27	Power Supply Subtotal	11,505,383	MWh		754,111		782,238
28							
29	PSCR	11,505,383	MWh	0.00000	0	0.00000	0
30	REPS	2,079	Cust.	0.0	0	0.0	0
31	Total Full Service Power Supply	11,505,383	MWh	6.55¢	754,111	6.80¢	782,238
32							
33	Full Service Distribution	Quantity	Units				
34							
35	Service Charge - PV	1,949	Cust.	70	1,637	70	1,637
36	Service Charge - SV	70	Cust.	375	315	375	315
37	Service Charge - TV	60	Cust.	375	270	375	270
38	<u>Distribution Charges</u>						
39	Primary	15,679,728	kW	6.15	96,430	6.66	104,460
40		5,852,418	MWh				
41	Subtransmission	3,118,737	kW	1.96	6,113	1.82	5,677
42		1,298,106	MWh				
43	Transmission	8,008,087	kW	0.86	6,887	0.99	7,938
44		4,354,860	MWh				
45	<u>Substation Credit</u>						
46	Demand	3,035,972	kW	(0.30)	(911)	(0.30)	(911)
47	Energy	181,296	MWh	(0.0004)	(73)	(0.0004)	(73)
48	Distribution System	11,505,383	MWh	0.96¢	110,668	1.04¢	119,313
49							
50	IRM - PV	15,679,728	kW	0.0727	1,140	0.0727	1,140
51	IRM - SV	3,118,737	kW	0.0312	97	0.0312	97
52	IRM - TV	8,008,087	kW	0.0000	0	0.0000	0
53	Nuclear Decommissioning	11,505,383	MWh	0.000882	10,148	0.000882	10,148
54	Energy Waste Reduction	2,463	Meters	1,237.99	36,597	1,237.99	36,597
55	LIEAF	2,463	Meters	0.88	26	0.88	26
56	Distribution Surcharges	11,505,383	MWh	0.42¢	48,008	0.42¢	48,008
57							
58	Total Full Service Distribution	11,505,383	MWh	1.38¢	158,676	1.45¢	167,321
59	Total Full Service D11	11,505,383	MWh	7.93¢	912,788	8.25¢	949,560

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Supply Rate - D11 (Cont'd)
All Voltages

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Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
60	Choice Distribution						
61	Capacity						
62	Power Supply Demand	0	kW	3.56	0	9.19	0
63	<u>Voltage Level Discount</u>						
64	Subtransmission	0	kW	(0.07)	0	(0.19)	0
65	Transmission	0	kW	(0.15)	0	(0.39)	0
66							
67	<u>Energy</u>						
68	On-Peak	0	MWh	0.00000	0	0.00000	0
69	Off-Peak	0	MWh	0.00000	0	0.00000	0
70	Total Energy	0	MWh				
71							
72	<u>Voltage Level Discount</u>						
73	Subtransmission	0	MWh	0.00000	0	0.00000	0
74	Transmission	0	MWh	0.00000	0	0.00000	0
75	Total Capacity	0	MWh		0		0
76							
77	Service Charge - PV	530	Cust.	70	445	70	445
78	Service Charge - SV	11	Cust.	375	50	375	50
79	Service Charge - TV	8	Cust.	375	34	375	34
80	<u>Distribution Charges</u>						
81	Primary	5,033,729	kW	6.15	30,957	6.66	33,535
82		2,011,974	MWh				
83	Subtransmission	558,645	kW	1.96	1,095	1.82	1,017
84		204,630	MWh				
85	Transmission	2,289,408	kW	0.86	1,969	0.99	2,269
86		831,189	MWh				
87	Substation Credit						
88	Demand	1,797,568	kW	(0.30)	(539)	(0.30)	(539)
89	Energy	41,020	MWh	(0.0004)	(16)	(0.0004)	(16)
90	Distribution System	3,047,793	MWh	1.12¢	33,995	1.21¢	36,795
91							
92	IRM - PV	5,033,729	kW	0.0727	366	0.0727	366
93	IRM - SV	558,645	kW	0.0312	17	0.0312	17
94	IRM - TV	2,289,408	kW	0	0	0	0
95	Nuclear Decommissioning	3,047,793	MWh	0.000882	2,688	0.000882	2,688
96	Energy Waste Reduction	631	Meters	1,237.99	9,367	1,237.99	9,367
97	LIEAF	631	Meters	0.88	7	0.88	7
98	Distribution Surcharges	3,047,793	MWh	0.41¢	12,446	0.41¢	12,446
99							
100	Total Choice D11	3,047,793	MWh	1.52¢	46,440	1.62¢	49,241
101							
102	Total D11	14,553,177	MWh	6.59¢	959,228	6.86¢	998,800
103	Increase/Decrease (\$)						39,572

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Educational Institute - D6.2
All Voltages

Case No.: U-21534
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Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
	Capacity					
1	Power Supply Demand	1,641,257 kW	3.58	5,876	10.79	17,701
2						
3	<u>Voltage Level Adjustment</u>					
4	Subtransmission	783,019 kW	(0.07)	(55)	(0.22)	(172)
5	Transmission	0 kW	(0.15)	0	(0.45)	0
6						
7	<u>Energy</u>					
8	On-Peak	195,100 MWh	0.00000	0	0.00000	0
9	Off-Peak	503,918 MWh	0.00000	0	0.00000	0
10	Total Energy	699,018 MWh				
11						
12	<u>Voltage Level Discount</u>					
13	Subtransmission	326,833 MWh	0.00000	0	0.00000	0
14	Transmission	0 MWh	0.00000	0	0.00000	0
15	Total Capacity	699,018 MWh		5,821		17,530
16						
17	Non-Capacity					
18	Power Supply Demand	1,641,257 kW	10.04	16,478	4.56	7,479
19	<u>Voltage Level Adjustment</u>					
20	Subtransmission	783,019 kW	(0.18)	(141)	(0.09)	(73)
21	Transmission	0 kW	(0.40)	0	(0.19)	0
22						
23						
24	<u>Energy</u>					
25	On-Peak	195,100 MWh	0.04322	8,432	0.04837	9,436
26	Off-Peak	503,918 MWh	0.04022	20,268	0.04537	22,861
27	<u>Voltage Level Discount</u>					
28	Subtransmission	326,833 MWh	(0.00073)	(239)	(0.00082)	(267)
29	Transmission	0 MWh	(0.00162)	0	(0.00182)	0
30	Power Supply Subtotal	699,018 MWh		50,619		56,966
31						
32	PSCR	699,018 MWh	0.00000	0	0.00000	0
33	REPS	123 Cust.	0.0	0	0.0	0
34	Total Full Service Power Supply	699,018 MWh	7.24¢	50,619	8.15¢	56,966
35						
36	Full Service Distribution	Quantity Units				
37						
38	Service Charge - PV	117 Cust.	70	98	70	98
39	Service Charge - SV	6 Cust.	375	27	375	27
40	Service Charge - TV	0 Cust.	375	0	375	0
41	<u>Distribution Charges</u>					
42	Primary	1,127,347 kW	6.15	6,933	6.66	7,510
43		372,184 MWh				
44	Subtransmission	999,979 kW	1.96	1,960	1.82	1,820
45		326,833 MWh				
46	Transmission	0 kW	0.86	0	0.99	0
47		0 MWh				
48	<u>Substation Credit</u>					
49	Demand	13,544 kW	(0.30)	(4)	(0.30)	(4)
50	Energy	0 MWh	(0.0004)	(0)	(0.0004)	(0)
51	Distribution System	699,018 MWh	1.29¢	9,014	1.35¢	9,452
52						
53	IRM - PV	1,127,347 kW	0.0727	82	0.0727	82
54	IRM - SV	999,979 kW	0.0312	31	0.0312	31
52	IRM - TV	0 kW	0	0	0	0
53	Nuclear Decommissioning	699,018 MWh	0.000882	617	0.000882	617
54	Energy Waste Reduction	146 Meters	1,237.99	2,169	1,237.99	2,169
55	LIEAF	146 Meters	0.88	2	0.88	2
56	Distribution Surcharges	699,018 MWh	0.41¢	2,900	0.41¢	2,900
57						
58	Total Full Service Distribution	699,018 MWh	1.70¢	11,915	1.77¢	12,352
59	Total Full Service D6.2	699,018 MWh	8.95¢	62,534	9.92¢	69,319

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Educational Institute - D6.2 (Cont'd)
All Voltages

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Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
60	Choice Distribution					
61	Capacity					
62	Power Supply Demand	kW	3.58	0	10.79	0
63						
64	Energy					
65	On-Peak	MWh	0.00000	0	0.00000	0
66	Off-Peak	MWh	0.00000	0	0.00000	0
67	Total Energy	MWh				
68						
69	Voltage Level Adjustment					
70	Subtransmission	kW	(0.07)	0	(0.22)	0
71	Transmission	kW	(0.15)	0	(0.45)	0
72	Total Capacity					0
73						
74	Service Charge - PV	153 Cust.	70	129	70	129
75	Service Charge - SV	0 Cust.	375	0	375	0
76	Service Charge - TV	0 Cust.	375	0	375	0
77	Distribution Charges					
78	Primary	1,528,071 kW	6.15	9,398	6.66	10,180
79		394,774 MWh				
80	Subtransmission	0 kW	1.96	0	1.82	0
81		0 MWh				
82	Transmission	0 kW	0.86	0	0.99	0
83		0 MWh				
84	Substation Credit					
85	Demand	0 kW	(0.30)	0	(0.30)	0
86	Energy	0 MWh	(0.0004)	0	(0.0004)	0
87	Distribution System	394,774 MWh	2.41¢	9,526	2.61¢	10,309
88						
89	IRM - PV	1,528,071 kW	0.0727	111	0.0727	111
90	IRM - SV	0 kW	0.0312	0	0.0312	0
91	IRM - TV	0 kW	0	0	0	0
92	Nuclear Decommissioning	394,774 MWh	0.000882	348	0.000882	348
93	Energy Waste Reduction	156 Meters	1,237.99	2,314	1,237.99	2,314
94	LIEAF	156 Meters	0.88	2	0.88	2
95	Distribution Surcharges	394,774 MWh	0.70¢	2,775	0.70¢	2,775
96						
97	Total Choice D6.2	394,774 MWh	3.12¢	12,301	3.31¢	13,083
98						
99	Total D6.2	1,093,792 MWh	6.84¢	74,835	7.53¢	82,402
100	Increase/Decrease (\$)					7,567

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rate - D8
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Power Supply Demand	941,965	kW	1.62	1,526	4.24	3,993
2	<u>Voltage Level Adjustment</u>						
3	Subtransmission	112,036	kW	(0.03)	(3)	(0.09)	(10)
4	Transmission	153,588	kW	(0.07)	(11)	(0.18)	(27)
5							
6	Product Protection Demand	135,807	kW	3.56	483	9.19	1,247
7	<u>Voltage Level Adjustment</u>						
8	Subtransmission	8,292	kW	(0.07)	(1)	(0.19)	(2)
9	Transmission	65,050	kW	(0.15)	(10)	(0.39)	(25)
10							
11	<u>Energy</u>						
12	On-Peak	135,663	MWh	0.00000	0	0.00000	0
13	Off-Peak	374,067	MWh	0.00000	0	0.00000	0
14	Total Energy	509,730	MWh				
15							
16	<u>Voltage Level Discount</u>						
17	Subtransmission	62,933	MWh	0.00000	0	0.00000	0
18	Transmission	125,103	MWh	0.00000	0	0.00000	0
19	Total Capacity	509,730	MWh		1,985		5,176
20							
21	Non-Capacity						
22	Power Supply Demand	941,965	kW	8.50	8,007	6.00	5,650
23	<u>Voltage Level Adjustment</u>						
24	Subtransmission	112,036	kW	(0.15)	(17)	(0.12)	(14)
25	Transmission	153,588	kW	(0.33)	(51)	(0.25)	(39)
26							
27	Product Protection Demand	135,807	kW	13.33	1,810	8.35	1,134
28	<u>Voltage Level Discount</u>						
29	Subtransmission	8,292	kW	(0.24)	(2)	(0.17)	(1)
30	Transmission	65,050	kW	(0.53)	(34)	(0.35)	(23)
31							
32	<u>Energy</u>						
33	On-Peak	135,663	MWh	0.04257	5,775	0.04388	5,953
34	Off-Peak	374,067	MWh	0.03257	12,183	0.03388	12,674
35	<u>Voltage Level Discount</u>						
36	Subtransmission	62,933	MWh	(0.00062)	(39)	(0.00064)	(41)
37	Transmission	125,103	MWh	(0.00138)	(173)	(0.00143)	(179)
38	Power Supply Subtotal	509,730	MWh		29,445		30,290
39							
40	PSCR	509,730	MWh	0.00000	0	0.00000	0
41	REPS	125	Cust.	0.00	0	0.00	0
42	Total Full Service Power Supply	509,730	MWh	5.78¢	29,445	5.94¢	30,290
43							
44	Full Service Distribution	Quantity	Units				
45							
46	Service Charge - PV	119	Cust.	70	100	70	100
47	Service Charge - SV	4	Cust.	375	18	375	18
48	Service Charge - TV	2	Cust.	375	9	375	9
49	<u>Distribution Charges</u>						
50	Primary	880,229	kW	6.15	5,413	6.66	5,864
51		321,694	MWh				
52	Subtransmission	129,679	kW	1.96	254	1.82	236
53		62,933	MWh				
54	Transmission	277,821	kW	0.86	239	0.99	275
55		125,103	MWh				
56	<u>Substation Credit</u>						
57	Demand	268,469	kW	(0.30)	(81)	(0.30)	(81)
58	Energy	0	MWh	(0.0004)	0	(0.0004)	0
59	Distribution System	509,730	MWh	1.17¢	5,953	1.26¢	6,422
60							
61	IRM - PV	880,229	kW	0.0727	64	0.0727	64
62	IRM - SV	129,679	kW	0.0312	4	0.0312	4
63	IRM - TV	277,821	kW	0	0	0	0
64	Nuclear Decommissioning	509,730	MWh	0.000882	450	0.000882	450
65	Energy Waste Reduction	133	Meters	1,237.99	1,979	1,237.99	1,979
66	LIEAF	133	Meters	0.88	1	0.88	1
67	Distribution Surcharges	509,730		0.49¢	2,498	0.49¢	2,498
68							
69	Total Full Service Distribution	509,730	MWh	1.66¢	8,451	1.75¢	8,920
70	Total Full Service D8	509,730	MWh	7.43¢	37,896	7.69¢	39,210

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rate - D8 (Cont'd)
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present Rate	(d) Revenue (\$000)	(e) Proposed Rate	(f) Revenue (\$000)
71	Choice Distribution	Quantity	Units				
72	Capacity						
73	Power Supply Demand	0	kW	1.62	0	4.24	0
74	<u>Voltage Level Discount</u>						
75	Subtransmission	0	kW	(0.03)	0	(0.09)	0
76	Transmission	0	kW	(0.07)	0	(0.18)	0
77							
78	Product Protection Demand	0	kW	3.56	0	9.19	0
79	<u>Voltage Level Discount</u>						
80	Subtransmission	0	kW	(0.07)	0	(0.19)	0
81	Transmission	0	kW	(0.15)	0	(0.39)	0
82							
83	<u>Energy</u>						
84	On-Peak	0	MWh	0.00000	0	0.00000	0
85	Off-Peak	0	MWh	0.00000	0	0.00000	0
86	Total Energy	0	MWh				
87							
88	<u>Voltage Level Discount</u>						
89	Subtransmission	0	MWh	0.00000	0	0.00000	0
90	Transmission	0	MWh	0.00000	0	0.00000	0
91	Total Capacity	0	MWh				0
92							
93	Service Charge - PV	10	Cust.	70	8	70	8
94	Service Charge - SV	2	Cust.	375	9	375	9
95	Service Charge - TV	0	Cust.	375	0	375	0
96	<u>Distribution Charges</u>						
97	Primary	226,275	kW	6.15	1,392	6.66	1,507
98		110,144	MWh				
99	Subtransmission	66,324	kW	1.96	130	1.82	121
100		23,118	MWh				
101	Transmission	0	kW	0.86	0	0.99	0
102		0	MWh				
103	<u>Substation Credit</u>						
104	Demand	0	kW	(0.30)	0	(0.30)	0
105	Energy	0	MWh	(0.0004)	0	(0.0004)	0
106	Distribution System	133,261	MWh	1.15¢	1,539	1.23¢	1,646
107							
108	IRM - PV	226,275	kW	0.072700	16	0.072700	16
109	IRM - SV	66,324	kW	0.031200	2	0.031200	2
110	IRM - TV	0	kW	0.000000	0	0.000000	0
111	Nuclear Decommissioning	133,261	MWh	0.000882	118	0.000882	118
112	Energy Waste Reduction	16	Meters	1,237.99	233	1,237.99	233
113	LIEAF	16	Meters	0.88	0	0.88	0
114	Distribution Surcharges	133,261	MWh	0.28¢	370	0.28¢	370
115							
116	Total Choice D8	133,261	MWh	1.43¢	1,909	1.51¢	2,015
117							
118	Total D8	642,991	MWh	6.19¢	39,805	6.41¢	41,225
119	Increase/Decrease (\$)						1,421

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
All Electric School Building Rate - D10
Primary Voltage

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants Quantity Units	(c) Present Rate	(d) Present Revenue (\$000)	(e) Proposed Rate	(f) Proposed Revenue (\$000)
	Full Service Power Supply					
	Capacity					
1	Energy					
2	Energy -- Winter	14,018 MWh	0.00094	13	0.01445	203
3	Energy -- Summer	6,872 MWh	0.02107	145	0.03458	238
4	Total Capacity	20,890 MWh		158		440
5						
6	Non-Capacity					
7	Energy	20,890 MWh	0.07430	1,552	0.06384	1,334
8	Power Supply Subtotal					
9						
10	PSCR	20,890 MWh	0.00000	0	0.00000	0
11	REPS	19 Cust.	0.00	0	0.00	0
12	Total Full Service Power Supply	20,890 MWh	8.19¢	1,710	8.49¢	1,774
13						
14	Full Service Distribution					
15						
16	Service Charge	19 Cust.	70	16	70	16
17						
18	<u>Distribution Charges</u>					
19	Primary	20,890 MWh	0.01968	411	0.01973	412
20	Distribution System	20,890 MWh	2.04¢	427	2.05¢	428
21						
22	IRM	20,890 MWh	0.000233	5	0.000233	5
23	Nuclear Decommissioning	20,890 MWh	0.000882	18	0.000882	18
24	Energy Waste Reduction	19 Meters	1,237.99	283	1,237.99	283
25	LIEAF	19 Meters	0.88	0	0.88	0
26	Distribution Surcharges	20,890 MWh	1.47¢	307	1.47¢	307
27						
28	Total Full Service Distribution	20,890 MWh	3.51¢	734	3.52¢	735
29	Total Full Service D10	20,890 MWh	11.70¢	2,444	12.01¢	2,509
30						
31	Choice Distribution					
32	Capacity					
33	Energy					
34	Energy -- Winter	0 MWh	0.00094	0	0.01445	0
35	Energy -- Summer	0 MWh	0.02107	0	0.03458	0
36	Total Capacity	0 MWh				0
37						
38	Service Charge	12 Cust.	70	10	70	10
39						
40	<u>Distribution Charges</u>					
41	Primary	13,396 MWh	0.01968	264	0.01973	264
42	Distribution System	13,396 MWh	2.04¢	274	2.05¢	274
43						
44	IRM	13,396 MWh	0.000233	3	0.000233	3
45	Nuclear Decommissioning	13,396 MWh	0.000882	12	0.000882	12
46	Energy Waste Reduction	12 Meters	1,237.99	178	1,237.99	178
47	LIEAF	12 Meters	0.88	0	0.88	0
48	Distribution Surcharges	13,396 MWh	1.44¢	193	1.44¢	193
49						
50	Total Choice D10	13,396 MWh	3.49¢	467	3.49¢	468
51						
52	Total D10	34,286 MWh	8.49¢	2,911	8.68¢	2,977
53	Increase/Decrease (\$)					65

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
EXPERIMENTAL LARGE CUSTOMER LOW
PEAK DEMAND SUPPLY RATE - D12
All Voltages

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Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Power Supply Demand (October through May)	0	kW	0.32	0	0.33	0
2	Power Supply Demand (June through September)	0	kW	8.00	0	8.30	0
3							
4	<u>Voltage Level Discount - Transmission</u>						
5	CVLD (October through May)	0	kW	(0.005)	0	(0.005)	0
6	CVLD (June through September)	0	kW	(0.14)	0	(0.15)	0
7							
8	Total Capacity				0		0
9							
10	Non-Capacity						
11	Power Supply Demand (October through May)	0	kW	0.32	0	0.33	0
12	Power Supply Demand (June through September)	0	kW	41.16	0	42.70	0
13							
14	<u>Voltage Level Discount - Transmission</u>						
15	NCVLD (October through May)	0	kW	(0.005)	0	(0.005)	0
16	NCVLD (June through September)	0	kW	(0.70)	0	(0.73)	0
17							
18	<u>Energy</u>						
19	On-Peak	0	MWh	0.04112	0	0.04265	0
20	Off-Peak	0	MWh	0.03611	0	0.03746	0
21							
22	<u>Voltage Level Discount - Transmission</u>	0	MWh	(0.00056)	0	(0.00058)	0
23							
24	Power Supply Subtotal	0	MWh		0		0
25							
26	PSCR	0	MWh	0.00000	0	0.00000	0
27	REPS	0	Cust.	0.0	0	0.0	0
28	Total Full Service Power Supply	0	MWh	#DIV/0!	0	#DIV/0!	0
29							
30	Full Service Distribution	Quantity	Units				
31							
32	Service Charge - SV	0	Cust.	375	0	375	0
33	Service Charge - TV	0	Cust.	375	0	375	0
34	<u>Distribution Charges</u>						
35	Subtransmission	0	kW	1.96	0	1.82	0
36		0	MWh				
37	Transmission	0	kW	0.86	0	0.99	0
38		0	MWh				
39	<u>Substation Credit</u>						
40	Demand	0	kW	(0.30)	0	(0.30)	0
41	Energy	0	MWh	(0.0004)	0	(0.0004)	0
42	Distribution System	0	MWh	#DIV/0!	0	#DIV/0!	0
43							
44	IRM - SV	0	kW	0.031200	0	0.031200	0
45	IRM - TV	0	kW	0.000000	0	0.000000	0
46	Nuclear Decommissioning	0	MWh	0.000882	0	0.000882	0
47	Energy Waste Reduction	0	Meters	1,237.99	0	1,237.99	0
48	LIEAF	0	Meters	0.88	0	0.88	0
49	Distribution Surcharges	0	MWh	#DIV/0!	0	#DIV/0!	0
50							
51	Total Full Service Distribution	0	MWh	#DIV/0!	0	#DIV/0!	0
52	Total Full Service D12	0	MWh	#DIV/0!	0	#DIV/0!	0

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
XL High Load Factor Rate - D13
All Voltages

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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Capacity	200,000	MWh	0.01514	3,028	0.01514	3,028
2	Non-Capacity	200,000	MWh	0.03430	6,860	0.03287	6,574
3	Transmission	200,000	MWh	0.00304	608	0.00308	616
4	Power Supply Subtotal	200,000	MWh		10,496		10,218
5							
6	REPS	3	Cust.	0.00	0	0.00	0
7	Total Full Service Power Supply	200,000	MWh	5.25¢	10,496	5.11¢	10,218
8							
9	Full Service Distribution	Quantity	Units				
10							
11	Service Charge - PV	1	Cust.	70	1	70	1
12	Service Charge - SV	0	Cust.	375	0	375	0
13	Service Charge - TV	2	Cust.	375	9	375	9
14							
15	Distribution Charges						
16	Primary	32,850	MWh	0.00936	307	0.01014	333
17	Sub-transmission	0	MWh	0.00298	0	0.00277	0
18	Transmission	167,150	MWh	0.00131	219	0.00151	252
19							
20	Administration Charge	200,000	MWh	0.00015	30	0.00015	30
21							
22	<u>Substation Credit</u>						
23	Primary Side		MWh	(0.00040)	0	(0.00040)	0
24	Customer Owned		MWh	(0.00055)	0	(0.00055)	0
25							
26	Distribution System	200,000	MWh	0.28¢	566	0.31¢	625
27							
28	IRM - PV	32,850	MWh	0.000133	4	0.000133	4
29	IRM - SV	0	MWh	0.000057	0	0.000057	0
30	IRM - TV	167,150	MWh	0.000000	0	0.000000	0
31	Energy Waste Reduction	3	Meters	1,237.99	45	1,237.99	45
32	LIEAF	3	Meters	0.88	0	0.88	0
33	Distribution Surcharges	200,000	MWh	0.02¢	49	0.02¢	49
34							
35	Total Full Service Distribution	200,000	MWh	0.31¢	615	0.34¢	674
36	Total Full Service D13	200,000	MWh	5.56¢	11,111	5.45¢	10,892
37	Increase/Decrease (\$)						(219)

Michigan Public Service Commission
DTE Electric Company
Optional TOU Primary Supply Rate - D14
Designed Revenue Neutral to D11
All Voltages

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Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) (d) Proposed D11		(e) (f) Revenue Neutral Design	
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	June - September						
2	On Peak (11am - 7pm M-F, excl holidays)	1,070,182	MWh			0.02649	28,345
3	Off Peak	3,054,881	MWh			0.01576	48,149
4	October - May						
5	On Peak (11am - 7pm M-F, excl holidays)	1,824,363	MWh			0.01831	33,400
6	Off Peak	5,555,958	MWh			0.01576	87,569
7	<u>Voltage Level Discount</u>						
8	Subtransmission	1,298,106	MWh			(0.00030)	(394)
9	Transmission	4,354,860	MWh			(0.00068)	(2,945)
10	Total Capacity	11,505,383	MWh				
11							
12	Non-Capacity						
13	June - September						
14	On Peak (11am - 7pm M-F, excl holidays)	1,070,182	MWh			0.08024	85,873
15	Off Peak	3,054,881	MWh			0.04775	145,871
16	October - May						
17	On Peak (11am - 7pm M-F, excl holidays)	1,824,363	MWh			0.05547	101,189
18	Off Peak	5,555,958	MWh			0.04775	265,298
19	<u>Voltage Level Discount</u>						
20	Subtransmission	1,298,106	MWh			(0.00092)	(1,195)
21	Transmission	4,354,860	MWh			(0.00205)	(8,922)
22	Power Supply Subtotal	11,505,383	MWh		0		782,238
23							
24	PSCR	11,505,383	MWh	0.00000	0	0.00000	0
25	REPS	2,079	Cust.	0.0	0	0.0	0
26	Total Full Service Power Supply	11,505,383	MWh	6.80¢	782,238	6.80¢	782,238
27							
28	Full Service Distribution	Quantity	Units				
29							
30	Service Charge - PV	1,949	Cust.	70	1,637	70	1,637
31	Service Charge - SV	70	Cust.	375	315	375	315
32	Service Charge - TV	60	Cust.	375	270	375	270
33	<u>Distribution Charges</u>						
34	Primary	15,679,728	kW	6.66	104,460	6.66	104,460
35		5,852,418	MWh				
36	Subtransmission	3,118,737	kW	1.82	5,677	1.82	5,677
37		1,298,106	MWh				
38	Transmission	8,008,087	kW	0.99	7,938	0.99	7,938
39		4,354,860	MWh				
40	<u>Substation Credit</u>						
41	Demand	3,035,972	kW	(0.30)	(911)	(0.30)	(911)
42	Energy	181,296	MWh	(0.0004)	(73)	(0.0004)	(73)
43	Distribution System	11,505,383	MWh	1.04¢	119,313	1.04¢	119,313
44							
45	IRM - PV	15,679,728	kW	0.0727	1,140	0.0727	1,140
46	IRM - SV	3,118,737	kW	0.0312	97	0.0312	97
47	IRM - TV	8,008,087	kW	0	0	0.0000	0
48	Nuclear Decommissioning	11,505,383	MWh	0.000882	10,148	0.000882	10,148
49	Energy Waste Reduction	2,463	Meters	1,237.99	36,597	1,237.99	36,597
50	LIEAF	2,463	Meters	0.88	26	0.88	26
51	Distribution Surcharges	11,505,383	MWh	0.42¢	48,008	0.42¢	48,008
52							
53	Total Full Service Distribution	11,505,383	MWh	1.45¢	167,321	1.45¢	167,321
54	Total Full Service D14	11,505,383	MWh	8.25¢	949,560	8.25¢	949,560

Michigan Public Service Commission
DTE Electric Company
Optional TOU Primary Supply Rate - D14 Cont'd
Designed Revenue Neutral to D11
All Voltages

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Schedule: F3 Revised
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Line No.	(a) Description	(b) Billing Determinants		(c) (d) Proposed D11		(e) (f) Revenue Neutral Design	
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
55	Choice Distribution						
56	Capacity						
57	June - September						
58	On Peak (11am - 7pm M-F, excl holidays)	0	MWh			0.02649	0
59	Off Peak	0	MWh			0.01576	0
60	October - May						0
61	On Peak (11am - 7pm M-F, excl holidays)	0	MWh			0.01831	0
62	Off Peak	0	MWh			0.01576	0
63	<u>Voltage Level Discount</u>						0
64	Subtransmission	0	MWh			(0.00030)	0
65	Transmission	0	MWh			(0.00068)	0
66	Total Capacity	0	MWh		0		0
67							
68	Service Charge - PV	530	Cust.	70	445	70	445
69	Service Charge - SV	11	Cust.	375	50	375	50
70	Service Charge - TV	8	Cust.	375	34	375	34
71	<u>Distribution Charges</u>						
72	Primary	5,033,729	kW	6.66	33,535	6.66	33,535
73		2,011,974	MWh				
74	Subtransmission	558,645	kW	1.82	1,017	1.82	1,017
75		204,630	MWh				
76	Transmission	2,289,408	kW	0.99	2,269	0.99	2,269
77		831,189	MWh				
78	Substation Credit						
79	Demand	1,797,568	kW	(0.30)	(539)	(0.30)	(539)
80	Energy	41,020	MWh	(0.0004)	(16)	(0.0004)	(16)
81	Distribution System	3,047,793	MWh	1.21¢	36,795	1.21¢	36,795
82							
83	IRM - PV	5,033,729	kW	0.0727	366	0.0727	366
84	IRM - SV	558,645	kW	0.0312	17	0.0312	17
85	IRM - TV	2,289,408	kW	0	0	0	0
86	Nuclear Decommissioning	3,047,793	MWh	0.000882	2,688	0.000882	2,688
87	Energy Waste Reduction	631	Meters	1,237.99	9,367	1,237.99	9,367
88	LIEAF	631	Meters	0.88	7	0.88	7
89	Distribution Surcharges	3,047,793	MWh	0.41¢	12,446	0.41¢	12,446
90							
91	Total Choice D14	3,047,793	MWh	1.62¢	49,241	1.62¢	49,241
92							
93	Total D14	14,553,177	MWh	6.86¢	998,800	6.86¢	998,800
94	Increase/Decrease (\$)						0

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Alternative Metal Melting Rider - R1.1

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Exhibit: A-16
Schedule: F3 Revised
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Energy						
2	Secondary						
3	First 100 Hours Use	2,315	MWh	0.00706	16	0.01789	41
4	Excess Hours Use	803	MWh	0.00267	2	0.00676	5
5	Primary						
6	First 100 Hours Use	6,627	MWh	0.00525	35	0.01330	88
7	Excess Hours Use	712	MWh	0.00191	1	0.00484	3
8	Subtransmission						
9	First 100 Hours Use	15,552	MWh	0.00512	80	0.01297	202
10	Excess Hours Use	35,693	MWh	0.00178	64	0.00451	161
11	Transmission						
12	First 100 Hours Use	37,938	MWh	0.00434	165	0.01100	417
13	Excess Hours Use	25,522	MWh	0.00144	37	0.00365	93
14	Total Capacity	125,163	MWh		399		1,011
15							
16	Non-Capacity						
17	Energy	125,163	MWh	0.05251	6,572	0.04892	6,123
18	Power Supply Subtotal				6,971		7,134
19							
20	PSCR	125,163	MWh	0.00000	0	0.00000	0
21	REPS	17	Cust.	0.00	0	0.00	0
22	Total Full Service Power Supply	125,163	MWh	5.57¢	6,971	5.70¢	7,134
23							
24	Full Service Distribution	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
25							
26	Distribution Charges						
27	Secondary						
28	First 100 Hours Use	2,315	MWh	0.05288	122	0.06156	142
29	Excess Hours Use	803	MWh	0.05288	42	0.06156	49
30	Primary						
31	First 100 Hours Use	6,627	MWh	0.01832	121	0.02015	134
32	Excess Hours Use	712	MWh	0.01832	13	0.02015	14
33	Subtransmission						
34	First 100 Hours Use	15,552	MWh	0.00677	105	0.00532	83
35	Excess Hours Use	35,693	MWh	0.00677	242	0.00532	190
36	Transmission						
37	First 100 Hours Use	37,938	MWh	0.00274	104	0.00600	228
38	Excess Hours Use	25,522	MWh	0.00274	70	0.00600	153
39							
40	Substation Credit						
41	Energy	3,966	MWh	(0.00300)	(12)	(0.00300)	(12)
42	Distribution System	125,163	MWh	0.65¢	808	1.48¢	982
43							
44	IRM - DV	3,118	MWh	0.000555	2	0.000555	2
45	IRM - PV	7,339	MWh	0.000229	2	0.000229	2
46	IRM - SV	51,246	MWh	0.000104	5	0.000104	5
47	IRM - TV	63,460	MWh	0	0	0	0
48	Nuclear Decommissioning	125,163	MWh	0.000882	110	0.000882	110
49	Energy Waste Reduction	23	Meters	1,237.99	345	1,237.99	345
50	LIEAF	23	Meters	0.88	0	0.88	0
51	Distribution Surcharges	125,163	MWh	0.37¢	464	0.37¢	464
52							
53	Total Full Service Distribution	125,163	MWh	1.02¢	1,273	1.16¢	1,446
54	Total Full Service R1.1	125,163	MWh	6.59¢	8,244	6.86¢	8,580

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Alternative Metal Melting Rider - R1.1 (Cont'd)

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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
55	Choice Distribution					
56	Capacity					
57	Energy					
58	Secondary					
59	First 100 Hours Use	0 MWh	0.00706	0	0.01789	0
60	Excess Hours Use	0 MWh	0.00267	0	0.00676	0
61	Primary					
62	First 100 Hours Use	0 MWh	0.00525	0	0.01330	0
63	Excess Hours Use	0 MWh	0.00191	0	0.00484	0
64	Subtransmission					
65	First 100 Hours Use	0 MWh	0.00512	0	0.01297	0
66	Excess Hours Use	0 MWh	0.00178	0	0.00451	0
67	Transmission					
68	First 100 Hours Use	0 MWh	0.00434	0	0.01100	0
69	Excess Hours Use	0 MWh	0.00144	0	0.00365	0
70	Total Capacity	0 MWh				0
71						
72	Distribution Charges					
73	Secondary					
74	First 100 Hours Use	0 MWh	0.05288	0	0.06156	0
75	Excess Hours Use	0 MWh	0.05288	0	0.06156	0
76	Primary					
77	First 100 Hours Use	0 MWh	0.01832	0	0.02015	0
78	Excess Hours Use	0 MWh	0.01832	0	0.02015	0
79	Subtransmission					
80	First 100 Hours Use	0 MWh	0.00677	0	0.00532	0
81	Excess Hours Use	0 MWh	0.00677	0	0.00532	0
82	Transmission					
83	First 100 Hours Use	0 MWh	0.00274	0	0.00600	0
84	Excess Hours Use	0 MWh	0.00274	0	0.00600	0
85						
86	Substation Credit					
87	Energy	0 MWh	(0.00300)	0	(0.00300)	0
88	Distribution System	0 MWh		0		0
89						
90	IRM - DV	0 MWh	0.000555	0	0.000555	0
91	IRM - PV	0 MWh	0.000229	0	0.000229	0
92	IRM - SV	0 MWh	0.000104	0	0.000104	0
93	IRM - TV	0 MWh	0	0	0	0
94	Nuclear Decommissioning	0 MWh	0.000882	0	0.000882	0
95	Energy Optimization	0 Meters	1,237.99	0	1,237.99	0
96	LIEAF	0 Meters	0.88	0	0.88	0
97	Distribution Surcharges	0 MWh		0		0
98						
99	Total Choice R1.1	0 MWh		0		0
100						
101	Total R1.1	125,163 MWh	6.59¢	8,244	6.86¢	8,580
102	Increase/Decrease (\$)					336

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Electric Process Heat Rider - R1.2

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Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue (\$000)	(e) Proposed	(f) Revenue (\$000)
	Full Service Power Supply	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>	<u>Revenue (\$000)</u>	<u>Rate</u>	<u>Revenue (\$000)</u>
	Capacity						
1	<u>Energy</u>						
2	Secondary						
3	First 100 Hours Use	12,311	MWh	0.00706	87	0.01789	220
4	Excess Hours Use	22,552	MWh	0.00267	60	0.00676	153
5	Primary						
6	First 100 Hours Use	81,851	MWh	0.00525	430	0.01330	1,089
7	Excess Hours Use	203,438	MWh	0.00191	389	0.00484	984
8	Subtransmission						
9	First 100 Hours Use	6,424	MWh	0.00512	33	0.01297	83
10	Excess Hours Use	20,884	MWh	0.00178	37	0.00451	94
11	Transmission						
12	First 100 Hours Use	0	MWh	0.00434	0	0.01100	0
13	Excess Hours Use	0	MWh	0.00144	0	0.00365	0
14	Total Capacity	347,461	MWh		1,035		2,623
15							
16	Non-Capacity						
17	<u>Energy</u>	347,461	MWh	0.05251	18,245	0.04892	16,997
18	Power Supply Subtotal	347,461			19,281		19,620
19							
20	PSCR	347,461	MWh	0.00000	0	0.00000	0
21	REPS	156	Cust.	0.00	0	0.00	0
22	Total Full Service Power Supply	347,461	MWh	5.55¢	19,281	5.65¢	19,620
23							
24	Full Service Distribution	<u>Quantity</u>	<u>Units</u>				
25							
26	<u>Distribution Charges</u>						
27	Secondary						
28	First 100 Hours Use	12,311	MWh	0.05288	651	0.06156	758
29	Excess Hours Use	22,552	MWh	0.05288	1,193	0.06156	1,388
30	Primary						
31	First 100 Hours Use	81,851	MWh	0.01832	1,500	0.02015	1,649
32	Excess Hours Use	203,438	MWh	0.01832	3,727	0.02015	4,099
33	Subtransmission						
34	First 100 Hours Use	6,424	MWh	0.00677	43	0.00532	34
35	Excess Hours Use	20,884	MWh	0.00677	141	0.00532	111
36	Transmission						
37	First 100 Hours Use	0	MWh	0.00274	0	0.00600	0
38	Excess Hours Use	0	MWh	0.00274	0	0.00600	0
39							
40	<u>Substation Credit</u>						
41	Energy	0	MWh	(0.00300)	0	(0.00300)	0
42	Distribution System	347,461	MWh	2.09¢	7,255	2.31¢	8,040
43							
44	IRM - DV	34,864	MWh	0.000555	19	0.000555	19
45	IRM - PV	285,289	MWh	0.000229	65	0.000229	65
46	IRM - SV	27,308	MWh	0.000104	3	0.000104	3
47	IRM - TV	0	MWh	0	0	0	0
48	Nuclear Decommissioning	347,461	MWh	0.000882	306	0.000882	306
49	Energy Waste Reduction	180	Meters	1,237.99	2,676	1,237.99	2,676
50	LIEAF	180	Meters	0.88	2	0.88	2
51	Distribution Surcharges	347,461	MWh	0.88¢	3,072	0.88¢	3,072
52							
53	Total Full Service Distribution	347,461	MWh	2.97¢	10,327	3.20¢	11,111
54	Total Full Service R1.2	347,461	MWh	8.52¢	29,608	8.84¢	30,732

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Electric Process Heat Rider - R1.2 (Cont'd)

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
55	Choice Distribution						
56	Capacity						
57	Energy						
58	Secondary						
59	First 100 Hours Use	0	MWh	0.00706	0	0.01789	0
60	Excess Hours Use	0	MWh	0.00267	0	0.00676	0
61	Primary						
62	First 100 Hours Use	0	MWh	0.00525	0	0.01330	0
63	Excess Hours Use	0	MWh	0.00191	0	0.00484	0
64	Subtransmission						
65	First 100 Hours Use	0	MWh	0.00512	0	0.01297	0
66	Excess Hours Use	0	MWh	0.00178	0	0.00451	0
67	Transmission						
68	First 100 Hours Use	0	MWh	0.00434	0	0.01100	0
69	Excess Hours Use	0	MWh	0.00144	0	0.00365	0
70	Total Capacity	0	MWh				0
71	Distribution Charges						
72	Secondary						
73	First 100 Hours Use	0	MWh	0.05288	0	0.06156	0
74	Excess Hours Use	0	MWh	0.05288	0	0.06156	0
75	Primary						
76	First 100 Hours Use	5,269	MWh	0.01832	97	0.02015	106
77	Excess Hours Use	17,116	MWh	0.01832	314	0.02015	345
78	Subtransmission						
79	First 100 Hours Use	0	MWh	0.00677	0	0.00532	0
80	Excess Hours Use	0	MWh	0.00677	0	0.00532	0
81	Transmission						
82	First 100 Hours Use	0	MWh	0.00274	0	0.00600	0
83	Excess Hours Use	0	MWh	0.00274	0	0.00600	0
84							
85	Substation Credit						
86	Energy			(0.00300)	0	(0.00300)	0
87	Distribution System	22,385	MWh	1.83¢	410	2.01¢	451
88							
89	IRM - DV	0	MWh	0.000555	0	0.000555	0
90	IRM - PV	22,385	MWh	0.000229	5	0.000229	5
91	IRM - SV	0	MWh	0.000104	0	0.000104	0
92	IRM - TV	0	MWh	0	0	0	0
93	Nuclear Decommissioning	22,385	MWh	0.000882	20	0.000882	20
94	Energy Waste Reduction	6	Meters	1,237.99	83	1,237.99	83
95	LIEAF	6	Meters	0.88	0	0.88	0
96	Distribution Surcharges	22,385	MWh	0.48¢	108	0.48¢	108
97							
98	Total Choice Distribution R1.2	22,385	MWh	2.31¢	518	2.50¢	559
99							
100	Total R1.2	369,846	MWh	8.15¢	30,125	8.46¢	31,291
101	Increase/Decrease (\$)						1,165

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Parallel Operation And Standby Service Rider - R3
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants Quantity Units	(c) Present Rate	(d) Present Revenue (\$000)	(e) Proposed Rate	(f) Proposed Revenue (\$000)
	Full Service Power Supply					
1	Station Power					
2	Capacity					
3	Administrative Charge	7,386 MWh	0.00000	0	0.00000	0
4	Station Power Capacity	7,386 MWh		0		0
5						
6	Non-Capacity					
7	MISO Energy Charge	7,386 MWh	0.03935	291	0.03935	291
8	Net Trans MISO MKT	7,386 MWh	0.00767	57	0.00769	57
9	Administrative Charge	7,386 MWh	0.00000	0	0.00000	0
10	Station Power PS Subtotal	7,386 MWh		347		347
11						
12	Standard R3					
13	Capacity					
14	<u>Power Supply Demand</u>					
15	Generation Reservation Fee	111,811 kW	0.13	15	0.33	37
16	Daily Demand	1,519,268 kW	0.36	547	0.92	1,395
17	Maintenance Demand	84,577 kW	0.18	15	0.46	39
18						
19						
20						
21						
22						
23	<u>Energy</u>					
24	Secondary	2,502 MWh	0.01010	25	0.02605	65
25	Primary Total	64,300 MWh	0.00000	0	0.00000	0
26		66,802 MWh				
27						
28						
29						
30						
31	Standard R3 Capacity	66,802 MWh		602		1,537
32						
33	Non-Capacity					
34	<u>Power Supply Demand</u>					
35	Generation Reservation Fee	111,811 kW	0.48	54	0.30	34
36	Daily Demand	1,519,268 kW	1.33	2,021	0.83	1,268
37	Maintenance Demand	84,577 kW	0.67	57	0.42	35
38						
39	<u>Energy</u>					
40	Secondary	2,502 MWh	0.07096	178	0.05870	147
41	Primary Total	64,300 MWh	0.04890	3,144	0.05016	3,225
42	Primary Off-Peak Discount	48,273 MWh	(0.010000)	(483)	(0.010000)	(483)
42						
43	<u>Voltage Level Discount</u>					
44	Subtransmission	24,083 MWh	(0.00062)	(15)	(0.00064)	(16)
45	Transmission	17,970 MWh	(0.00138)	(25)	(0.00143)	(26)
46	Standard R3 PS Subtotal	66,802		5,532		5,722
47						
48	PSCR	66,802 MWh	0.00000	0	0.00000	0
49	REPS	40 Cust.	0.00	0	0.00	0
50	Total Full Service Power Supply	74,189 MWh	7.93¢	5,880	8.18¢	6,069

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Parallel Operation And Standby Service Rider - R3 (Cont'd)
All Voltages

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 Schedule: F3 Revised
 Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d)	(e) Proposed	(f)
51	Full Service Distribution	<u>Quantity</u> <u>Units</u>				
52	<u>Service Charge</u>					
53	Secondary	13 Cust.	70	11	70	11
54	Service Charge - PV	14 Cust.	70	12	70	12
55	Service Charge - SV	12 Cust.	375	54	375	54
56	Service Charge - TV	1 Cust.	375	5	375	5
57	<u>Distribution Charges</u>					
58	Secondary	15,050 kW	13.22	199	15.39	232
59		2,502 MWh	0.05288	132	0.06156	154
60	Primary	78,089 kW	6.15	480	6.66	520
61		22,247 MWh				
62	Subtransmission	483,801 kW	1.96	948	1.82	881
63		24,083 MWh				
64	Transmission	92,427 kW	0.86	79	0.99	92
65		17,970 MWh				
66	<u>Substation Credit</u>					
67	Demand	101,092 kW	(0.30)	(30)	(0.30)	(30)
68	Energy	8,892 MWh	(0.00040)	(4)	(0.00040)	(4)
69	Distribution System	66,802 MWh	2.82¢	1,886	2.88¢	1,925
70						
71	IRM - DV	2,502 MWh	0.000595	1	0.000595	1
72	IRM - PV	78,089 kW	0.0727	6	0.072700	6
73	IRM - SV	483,801 kW	0.0312	15	0.031200	15
74	IRM - TV	92,427 kW	0.0000	0	0.000000	0
75	Nuclear Decommissioning	66,802 MWh	0.000882	59	0.000882	59
76	Energy Waste Reduction	46 Meters	1,237.99	678	1,237.99	678
77	LIEAF	46 Meters	0.88	0	0.88	0
78	Distribution Surcharges	66,802 MWh	1.14¢	760	1.14¢	760
79						
80	Total Full Service Distribution	66,802 MWh	3.96¢	2,646	4.02¢	2,685
81	Total Full Service R3	74,189 MWh	11.49¢	8,526	11.80¢	8,754
82	Increase/Decrease (\$)					229

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rider - R10
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Full Service Power Supply					
2	Capacity					
3	Administrative Charge	998,081 MWh	0.00000	0	0.00000	0
4	Total Capacity	998,081 MWh				
5	Non-Capacity					
6	Administrative Charge	998,081 MWh	0.00000	0	0.00000	0
7	MISO Energy Charge	998,081 MWh	0.03935	39,274	0.03935	39,274
8	Net Trans MISO MKT	998,081 MWh	0.00767	7,655	0.00769	7,674
9	Voltage Level Service Adder					
10	Primary	30,650 MWh	5.50%	79	5.50%	79
11	Subtransmission	21,262 MWh	3.73%	37	3.73%	37
12	Transmission	946,169 MWh	1.56%	694	1.56%	694
13	Power Supply Subtotal	998,081 MWh		47,740		47,759
14	REPS	0 meters	0.00	0	0.00	0
15	Total Full Service Power Supply	998,081 MWh	4.78¢	47,740	4.79¢	47,759
16	Full Service Distribution					
17		Quantity Units				
18	Service Charge - PV	12 Cust.	70	10	70	10
19	Service Charge - SV	8 Cust.	375	36	375	36
20	Service Charge - TV	33 Cust.	375	149	375	149
21	Distribution Charges					
22	Primary	178,736 kW	6.15	1,099	6.66	1,191
23		30,650 MWh				
24	Subtransmission	65,584 kW	1.96	129	1.82	119
25		21,262 MWh				
26	Transmission	3,790,403 kW	0.86	3,260	0.99	3,757
27		946,169 MWh				
28	Substation Credit					
29	Demand	1,250,515 kW	(0.30)	(375)	(0.30)	(375)
30	Energy	144,780 MWh	(0.0004)	(58)	(0.0004)	(58)
31	Distribution System	998,081 MWh	0.43¢	4,249	0.48¢	4,829
32	IRM - PV	178,736 kW	0.0727	13	0.0727	13
33	IRM - SV	65,584 kW	0.0312	2	0.0312	2
34	IRM - TV	3,790,403 kW	0	0	0	0
35	Nuclear Decommissioning	998,081 MWh	0.000882	880	0.000882	880
36	Energy Waste Reduction	0 Meters	1,237.99	0	1,237.99	0
37	LIEAF	0 Meters	0.88	0	0.88	0
38	Distribution Surcharges	998,081 MWh	0.09¢	895	0.09¢	895
39	Total Full Service Distribution	998,081 MWh	0.52¢	5,145	0.57¢	5,724
40	Total Full Service R10	998,081 MWh	5.30¢	52,885	5.36¢	53,484

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rider - R10 (Cont'd)
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
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Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue (\$000)	(e) Proposed	(f) Revenue (\$000)
45	Choice Distribution	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>		<u>Rate</u>	<u>Revenue</u>
46	Capacity						
47	Administrative Charge	0	MWh	0.00000		0.00000	0
48	Total Capacity	0	MWh				0
49							
50	Service Charge - PV	0	Cust.	70	0	70	0
51	Service Charge - SV	0	Cust.	375	0	375	0
52	Service Charge - TV	0	Cust.	375	0	375	0
53	<u>Distribution Charges</u>						
54	Primary	0	kW	6.15	0	6.66	0
55							
56	Subtransmission	0	kW	1.96	0	1.82	0
57							
58	Transmission	0	kW	0.86	0	0.99	0
59							
60	<u>Substation Credit</u>						
61	Demand	0	kW	(0.30)	0	(0.30)	0
62	Energy	0	MWh	(0.0004)	0	(0.0004)	0
63	Distribution System	0	MWh		0		0
64							
65	IRM - PV	0	kW	0.0727	0	0.0727	0
66	IRM - SV	0	kW	0.0312	0	0.0312	0
67	IRM - TV	0	kW	0	0	0	0
68	Nuclear Decommissioning			0.000882	0	0.000882	0
69	Energy Waste Reduction			1,237.99	0	1,237.99	0
70	LIEAF	0	Meters	0.88	0	0.88	0
71	Distribution Surcharges				0		0
72							
73	Total Choice Distribution R10	0	MWh		0		0
74							
75	Total R10	998,081	MWh	5.30¢	52,885	5.36¢	53,484
76	Increase/Decrease (\$)						599

Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e)	(f)	(g) Proposed	(h) Non-Capacity	(i) Capacity	(j)
					Rate	Non-Capacity	Capacity	Rate	Capacity	Capacity	
		Quantity	Units		(\$/luminaire/ mth)	Energy	Energy	(\$/luminaire/ mth)	Energy	Energy	Revenue
					(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(\$000)
1	Overhead										
2	Mercury Vapor										
3	100 W	0	Lamps		15.04	4.46	0.00	0	16.13	4.66	0.00
4	175 W	3,129	Lamps		18.68	4.46	0.00	825	20.05	4.66	0.00
5	250 W	1	Lamps		22.32	4.46	0.00	0	23.98	4.66	0.00
6	400 W	54	Lamps		29.40	4.46	0.00	24	31.61	4.66	0.00
7	1,000 W	3	Lamps		60.24	4.46	0.00	3	64.81	4.66	0.00
8											
9	High Pressure Sodium Vapor										
10	100 W	3,245	Lamps		14.00	4.46	0.00	627	15.02	4.66	0.00
11	150 W	1	Lamps		16.71	4.46	0.00	0	17.94	4.66	0.00
12	250 W	399	Lamps		21.49	4.46	0.00	126	23.09	4.66	0.00
13	360 W	0	Lamps		25.11	4.46	0.00	0	27.00	4.66	0.00
14	400 W	31	Lamps		26.42	4.46	0.00	13	28.42	4.66	0.00
15	1,000 W	4	Lamps		53.23	4.46	0.00	3	57.33	4.66	0.00
16											
17	Metal Halide										
18	100 W	0	Lamps		14.03	4.46	0.00	0	15.06	4.66	0.00
19	150 W	0	Lamps		16.77	4.46	0.00	0	18.01	4.66	0.00
20	175 W	0	Lamps		18.14	4.46	0.00	0	19.49	4.66	0.00
21	250 W	0	Lamps		22.25	4.46	0.00	0	23.91	4.66	0.00
22	320 W	0	Lamps		26.09	4.46	0.00	0	28.04	4.66	0.00
23	400 W	0	Lamps		30.48	4.46	0.00	0	32.76	4.66	0.00
24	1,000 W	1	Lamps		63.38	4.46	0.00	1	68.16	4.66	0.00
25		0									
26	LED	0									
27	20 - 29 W	0	Lamps		11.20	4.46	0.00	0	12.00	4.66	0.00
28	30 - 39 W	0	Lamps		11.79	4.46	0.00	0	12.62	4.66	0.00
29	40 - 49 W	0	Lamps		12.37	4.46	0.00	0	13.25	4.66	0.00
30	50 - 59 W	722	Lamps		12.95	4.46	0.00	120	13.87	4.66	0.00
31	60 - 69 W	1,458	Lamps		13.53	4.46	0.00	254	14.49	4.66	0.00
32	70 - 79 W	11	Lamps		14.12	4.46	0.00	2	15.13	4.66	0.00
33	80 - 89 W	0	Lamps		14.70	4.46	0.00	0	15.75	4.66	0.00
34	90 - 99 W	0	Lamps		15.28	4.46	0.00	0	16.38	4.66	0.00
35	100 - 109 W	0	Lamps		15.86	4.46	0.00	0	17.01	4.66	0.00
36	110 - 119 W	4	Lamps		16.45	4.46	0.00	1	17.63	4.66	0.00
37	120 - 129 W	0	Lamps		17.03	4.46	0.00	0	18.26	4.66	0.00
38	130 - 139 W	140	Lamps		17.61	4.46	0.00	33	18.88	4.66	0.00
39	140 - 149 W	4	Lamps		18.14	4.46	0.00	1	19.45	4.66	0.00
40	150 - 159 W	0	Lamps		18.66	4.46	0.00	0	20.02	4.66	0.00
41	160 - 169 W	0	Lamps		19.18	4.46	0.00	0	20.58	4.66	0.00
42	170 - 179 W	0	Lamps		19.71	4.46	0.00	0	21.14	4.66	0.00
43	180 - 189 W	0	Lamps		20.23	4.46	0.00	0	21.71	4.66	0.00
44	190 - 199 W	0	Lamps		20.75	4.46	0.00	0	22.27	4.66	0.00
45	200 - 209 W	0	Lamps		21.28	4.46	0.00	0	22.83	4.66	0.00
46	210 - 219 W	2	Lamps		21.80	4.46	0.00	1	23.39	4.66	0.00
47	220 - 229 W	0	Lamps		22.32	4.46	0.00	0	23.95	4.66	0.00
48	230 - 239 W	5	Lamps		22.85	4.46	0.00	2	24.52	4.66	0.00
49	240 - 249 W	0	Lamps		23.37	4.46	0.00	0	25.09	4.66	0.00
50	250 - 259 W	0	Lamps		23.89	4.46	0.00	0	25.65	4.66	0.00
51	260 - 269 W	0	Lamps		24.42	4.46	0.00	0	26.21	4.66	0.00
52	270 - 279 W	0	Lamps		24.94	4.46	0.00	0	26.78	4.66	0.00
53	280 - 289 W	8	Lamps		25.47	4.46	0.00	3	27.34	4.66	0.00
54	290 - 299 W	14	Lamps		25.99	4.46	0.00	5	27.90	4.66	0.00
55	300 - 309 W	0	Lamps		26.51	4.46	0.00	0	28.47	4.66	0.00
56	310 - 319 W	0	Lamps		27.04	4.46	0.00	0	29.03	4.66	0.00
57	320 - 329 W	0	Lamps		27.56	4.46	0.00	0	29.59	4.66	0.00
58	330 - 339 W	0	Lamps		28.08	4.46	0.00	0	30.15	4.66	0.00
59	340 - 349 W	0	Lamps		28.61	4.46	0.00	0	30.72	4.66	0.00
60	350 - 359 W	0	Lamps		29.13	4.46	0.00	0	31.28	4.66	0.00
61	360 - 369 W	0	Lamps		29.65	4.46	0.00	0	31.84	4.66	0.00
62	370 - 379 W	0	Lamps		30.18	4.46	0.00	0	32.41	4.66	0.00
63	380 - 389 W	0	Lamps		30.70	4.46	0.00	0	32.97	4.66	0.00
64	390 - 399 W	0	Lamps		31.22	4.46	0.00	0	33.53	4.66	0.00

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Line No.	(a) Description	(b) Billing Determinants		(c) Present				(d) Proposed			
				Rate	Non-Capacity Energy	Capacity Energy	Revenue	Rate	Non- Capacity Energy	Capacity Energy	Revenue
		Quantity	Units	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)
65	Underground										
66	Mercury Vapor										
67	100 W	0	Lamps	27.60	4.46	0.00	0	27.51	4.66	0.00	0
68	175 W	1	Lamps	30.35	4.46	0.00	0	30.20	4.66	0.00	0
69	250 W	0	Lamps	35.65	4.46	0.00	0	35.43	4.66	0.00	0
70	400 W	0	Lamps	46.25	4.46	0.00	0	45.93	4.66	0.00	0
71	1,000 W	0	Lamps	86.55	4.46	0.00	0	85.76	4.66	0.00	0
72											
73	High Pressure Sodium Vapor										
74	70 W	0	Lamps	24.09	4.46	0.00	0	24.02	4.66	0.00	0
75	100 W	1	Lamps	24.86	4.46	0.00	0	24.76	4.66	0.00	0
76	150 W	0	Lamps	26.49	4.46	0.00	0	26.35	4.66	0.00	0
77	250 W	0	Lamps	29.75	4.46	0.00	0	29.53	4.66	0.00	0
78	400 W	0	Lamps	34.64	4.46	0.00	0	34.30	4.66	0.00	0
79	1,000 W	0	Lamps	54.21	4.46	0.00	0	53.37	4.66	0.00	0
80											
81	Metal Halide										
82	100 W	0	Lamps	30.54	4.46	0.00	0	24.76	4.66	0.00	0
83	150 W	0	Lamps	34.29	4.46	0.00	0	26.35	4.66	0.00	0
84	175 W	0	Lamps	36.17	4.46	0.00	0	27.15	4.66	0.00	0
85	250 W	0	Lamps	41.79	4.46	0.00	0	29.53	4.66	0.00	0
86	400 W	0	Lamps	53.05	4.46	0.00	0	34.30	4.66	0.00	0
87	1,000 W	0	Lamps	98.08	4.46	0.00	0	101.94	4.66	0.00	0
88											
89	LED										
90	20 - 29 W	0	Lamps	25.22	4.46	0.00	0	25.20	4.66	0.00	0
91	30 - 39 W	2	Lamps	25.66	4.46	0.00	1	25.63	4.66	0.00	1
92	40 - 49 W	0	Lamps	26.10	4.46	0.00	0	26.07	4.66	0.00	0
93	50 - 59 W	0	Lamps	26.55	4.46	0.00	0	26.51	4.66	0.00	0
94	60 - 69 W	0	Lamps	27.00	4.46	0.00	0	26.95	4.66	0.00	0
95	70 - 79 W	74	Lamps	27.41	4.46	0.00	25	27.36	4.66	0.00	25
96	80 - 89 W	0	Lamps	27.84	4.46	0.00	0	27.78	4.66	0.00	0
97	90 - 99 W	0	Lamps	28.25	4.46	0.00	0	28.18	4.66	0.00	0
98	100 - 109 W	0	Lamps	28.66	4.46	0.00	0	28.58	4.66	0.00	0
99	110 - 119 W	0	Lamps	29.09	4.46	0.00	0	29.01	4.66	0.00	0
100	120 - 129 W	0	Lamps	29.49	4.46	0.00	0	29.40	4.66	0.00	0
101	130 - 139 W	1	Lamps	29.89	4.46	0.00	0	29.79	4.66	0.00	0
102	140 - 149 W	0	Lamps	30.27	4.46	0.00	0	30.17	4.66	0.00	0
103	150 - 159 W	0	Lamps	30.65	4.46	0.00	0	30.54	4.66	0.00	0
104	160 - 169 W	0	Lamps	31.03	4.46	0.00	0	30.92	4.66	0.00	0
105	170 - 179 W	0	Lamps	31.41	4.46	0.00	0	31.29	4.66	0.00	0

Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e) Capacity	(f) Revenue	(g) Non-Capacity	(h) Capacity	(i) Capacity	(j) Revenue
					Rate	Energy	Energy	Rate	Energy	Energy	Revenue
		Quantity	Units		(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)
1	Overhead										
2	Mercury Vapor										
3	100 W	0	Lamps		15.04	4.46	0.00	0	16.13	4.66	0.00
4	175 W	3,454	Lamps		18.68	4.46	0.00	910	20.05	4.66	0.00
5	250 W	113	Lamps		22.32	4.46	0.00	37	23.98	4.66	0.00
6	400 W	916	Lamps		29.40	4.46	0.00	400	31.61	4.66	0.00
7	1,000 W	99	Lamps		60.24	4.46	0.00	91	64.81	4.66	0.00
8											
9	High Pressure Sodium Vapor										
10	100 W	2,248	Lamps		14.00	4.46	0.00	435	15.02	4.66	0.00
11	150 W	0	Lamps		16.71	4.46	0.00	0	17.94	4.66	0.00
12	250 W	3,950	Lamps		21.49	4.46	0.00	1,244	23.09	4.66	0.00
13	360 W	0	Lamps		25.11	4.46	0.00	0	27.00	4.66	0.00
14	400 W	2,086	Lamps		26.42	4.46	0.00	843	28.42	4.66	0.00
15	1,000 W	59	Lamps		53.23	4.46	0.00	50	57.33	4.66	0.00
16											
17	Metal Halide										
18	100 W	0	Lamps		14.03	4.46	0.00	0	15.06	4.66	0.00
19	150 W	0	Lamps		16.77	4.46	0.00	0	18.01	4.66	0.00
20	175 W	0	Lamps		18.14	4.46	0.00	0	19.49	4.66	0.00
21	250 W	0	Lamps		22.25	4.46	0.00	0	23.91	4.66	0.00
22	320 W	0	Lamps		26.09	4.46	0.00	0	28.04	4.66	0.00
23	400 W	3	Lamps		30.48	4.46	0.00	1	32.76	4.66	0.00
24	1,000 W	165	Lamps		63.38	4.46	0.00	158	68.16	4.66	0.00
25											
26	LED										
27	20 - 29 W	0	Lamps		11.20	4.46	0.00	0	12.00	4.66	0.00
28	30 - 39 W	9	Lamps		11.79	4.46	0.00	1	12.62	4.66	0.00
29	40 - 49 W	0	Lamps		12.37	4.46	0.00	0	13.25	4.66	0.00
30	50 - 59 W	1,909	Lamps		12.95	4.46	0.00	316	13.87	4.66	0.00
31	60 - 69 W	2,053	Lamps		13.53	4.46	0.00	358	14.49	4.66	0.00
32	70 - 79 W	230	Lamps		14.12	4.46	0.00	42	15.13	4.66	0.00
33	80 - 89 W	10	Lamps		14.70	4.46	0.00	2	15.75	4.66	0.00
34	90 - 99 W	0	Lamps		15.28	4.46	0.00	0	16.38	4.66	0.00
35	100 - 109 W	0	Lamps		15.86	4.46	0.00	0	17.01	4.66	0.00
36	110 - 119 W	6	Lamps		16.45	4.46	0.00	1	17.63	4.66	0.00
37	120 - 129 W	0	Lamps		17.03	4.46	0.00	0	18.26	4.66	0.00
38	130 - 139 W	2,438	Lamps		17.61	4.46	0.00	577	18.88	4.66	0.00
39	140 - 149 W	17	Lamps		18.14	4.46	0.00	4	19.45	4.66	0.00
40	150 - 159 W	0	Lamps		18.66	4.46	0.00	0	20.02	4.66	0.00
41	160 - 169 W	0	Lamps		19.18	4.46	0.00	0	20.58	4.66	0.00
42	170 - 179 W	0	Lamps		19.71	4.46	0.00	0	21.14	4.66	0.00
43	180 - 189 W	0	Lamps		20.23	4.46	0.00	0	21.71	4.66	0.00
44	190 - 199 W	0	Lamps		20.75	4.46	0.00	0	22.27	4.66	0.00
45	200 - 209 W	119	Lamps		21.28	4.46	0.00	35	22.83	4.66	0.00
46	210 - 219 W	467	Lamps		21.80	4.46	0.00	141	23.39	4.66	0.00
47	220 - 229 W	1	Lamps		22.32	4.46	0.00	0	23.95	4.66	0.00
48	230 - 239 W	1,186	Lamps		22.85	4.46	0.00	377	24.52	4.66	0.00
49	240 - 249 W	0	Lamps		23.37	4.46	0.00	0	25.09	4.66	0.00
50	250 - 259 W	0	Lamps		23.89	4.46	0.00	0	25.65	4.66	0.00
51	260 - 269 W	0	Lamps		24.42	4.46	0.00	0	26.21	4.66	0.00
52	270 - 279 W	0	Lamps		24.94	4.46	0.00	0	26.78	4.66	0.00
53	280 - 289 W	842	Lamps		25.47	4.46	0.00	302	27.34	4.66	0.00
54	290 - 299 W	1,592	Lamps		25.99	4.46	0.00	584	27.90	4.66	0.00
55	300 - 309 W	0	Lamps		26.51	4.46	0.00	0	28.47	4.66	0.00
56	310 - 319 W	0	Lamps		27.04	4.46	0.00	0	29.03	4.66	0.00
57	320 - 329 W	0	Lamps		27.56	4.46	0.00	0	29.59	4.66	0.00
58	330 - 339 W	0	Lamps		28.08	4.46	0.00	0	30.15	4.66	0.00
59	340 - 349 W	0	Lamps		28.61	4.46	0.00	0	30.72	4.66	0.00
60	350 - 359 W	0	Lamps		29.13	4.46	0.00	0	31.28	4.66	0.00
61	360 - 369 W	0	Lamps		29.65	4.46	0.00	0	31.84	4.66	0.00
62	370 - 379 W	0	Lamps		30.18	4.46	0.00	0	32.41	4.66	0.00
63	380 - 389 W	0	Lamps		30.70	4.46	0.00	0	32.97	4.66	0.00
64	390 - 399 W	8	Lamps		31.22	4.46	0.00	4	33.53	4.66	0.00

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Line No.	(a) Description	(b) Billing Determinants		(c) Present				(d)	(e)	(f)	(g) Proposed				(h)	(i)	(j)

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Municipal Street Lighting - E1 Option I - Company Owned Overhead

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Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e) Capacity	(f) Revenue	(g)	(h) Proposed	(i) Capacity	(j) Revenue
		Quantity	Units	Rate (\$/luminaire/ mth)	Non-Capacity Energy (\$/kWh)	Energy (\$/kWh)		Rate (\$/luminaire/ mth)	Non-Capacity Energy (\$/kWh)	Energy (\$/kWh)	
1	Overhead										
2	Mercury Vapor										
3	100 W	97	Lamps	25.34	4.46	0.00	32	27.80	4.66	0.00	35
4	175 W	1,644	Lamps	31.35	4.46	0.00	681	34.43	4.66	0.00	745
5	250 W	0	Lamps	37.52	4.46	0.00	0	41.13	4.66	0.00	0
6	400 W	386	Lamps	49.56	4.46	0.00	261	54.52	4.66	0.00	285
7	1,000 W	0	Lamps	105.40	4.46	0.00	0	116.02	4.66	0.00	0
8											
9	High Pressure Sodium Vapor										
10	70 W	948	Lamps	18.86	4.46	0.00	231	20.69	4.66	0.00	252
11	100 W	5,337	Lamps	21.53	4.46	0.00	1,509	23.64	4.66	0.00	1,651
12	150 W	0	Lamps	25.87	4.46	0.00	0	28.08	4.66	0.00	0
13	250 W	2,049	Lamps	33.61	4.46	0.00	940	36.97	4.66	0.00	1,028
14	360 W	0	Lamps	42.05	4.46	0.00	0	43.17	4.66	0.00	0
15	400 W	0	Lamps	45.12	4.46	0.00	0	45.42	4.66	0.00	0
16	1,000 W	0	Lamps	82.64	4.46	0.00	0	79.23	4.66	0.00	0
17											
18	Metal Halide										
19	70 W	1	Lamps	24.48	4.46	0.00	0	26.83	4.66	0.00	0
20	100 W	1	Lamps	24.83	4.46	0.00	0	27.24	4.66	0.00	0
21	150 W	0	Lamps	30.17	4.46	0.00	0	33.11	4.66	0.00	0
22	175 W	10	Lamps	32.83	4.46	0.00	4	36.05	4.66	0.00	5
23	250 W	1	Lamps	40.84	4.46	0.00	1	44.87	4.66	0.00	1
24	320 W	0	Lamps	47.70	4.46	0.00	0	52.42	4.66	0.00	0
25	400 W	6	Lamps	55.53	4.46	0.00	4	61.05	4.66	0.00	5
26	1,000 W	1	Lamps	114.64	4.46	0.00	2	126.11	4.66	0.00	2
27											
28	De-Energized										
29	Mercury Vapor										
30	100 W	0	Lamps	16.33	4.46	0.00	0	17.81	4.66	0.00	0.000
31	175 W	1	Lamps	20.78	4.46	0.00	0	22.65	4.66	0.00	0.272
32	250 W	0	Lamps	25.32	4.46	0.00	0	0.00	4.66	0.00	0.000
33	400 W	0	Lamps	33.95	4.46	0.00	0	36.97	4.66	0.00	0.000
34	1,000 W	0	Lamps	78.36	4.46	0.00	0	78.36	4.66	0.00	0.000
35											
36	High Pressure Sodium Vapor										
37	70 W	0	Lamps	12.20	4.46	0.00	0	13.32	4.66	0.00	0.000
38	100 W	4	Lamps	14.18	4.46	0.00	1	15.46	4.66	0.00	0.742
39	150 W	0	Lamps	17.39	4.46	0.00	0	0.00	4.66	0.00	0.000
40	250 W	1	Lamps	23.02	4.46	0.00	0	25.07	4.66	0.00	0.301
41	360 W	0	Lamps	31.20	4.46	0.00	0	31.20	4.66	0.00	0.000
42	400 W	0	Lamps	31.42	4.46	0.00	0	0.00	4.66	0.00	0.000
43	1,000 W	0	Lamps	64.29	4.46	0.00	0	64.29	4.66	0.00	0.000
44											
45	LED										
46	60 - 69 W	0	Lamps	12.16	4.46	0.00	0	13.01	4.66	0.00	0.000
47											
48	Dusk-Midnight										
49	Mercury Vapor										
50	100 W	0	Lamps	24.28	4.46	0.00	0	26.74	4.66	0.00	0.000
51	175 W	0	Lamps	29.50	4.46	0.00	0	32.58	4.66	0.00	0.000
52	250 W	0	Lamps	34.87	4.46	0.00	0	38.48	4.66	0.00	0.000
53	400 W	0	Lamps	45.32	4.46	0.00	0	50.28	4.66	0.00	0.000
54	1,000 W	0	Lamps	103.94	4.46	0.00	0	103.94	4.66	0.00	0.000
55											
56	High Pressure Sodium Vapor										
57	70 W	0	Lamps	18.11	4.46	0.00	0	19.95	4.66	0.00	0.000
58	100 W	0	Lamps	20.47	4.46	0.00	0	22.58	4.66	0.00	0.000
59	150 W	0	Lamps	24.28	4.46	0.00	0	26.49	4.66	0.00	0.000
60	250 W	2	Lamps	30.96	4.46	0.00	1	34.32	4.66	0.00	0.882
61	360 W	0	Lamps	38.23	4.46	0.00	0	39.35	4.66	0.00	0.000
62	400 W	4	Lamps	40.88	4.46	0.00	2	41.18	4.66	0.00	2.153
63	1,000 W	0	Lamps	72.04	4.46	0.00	0	68.63	4.66	0.00	0.000
64											
65	LED										
66	130 - 139 W	5	Lamps	25.97	4.46	0.00	2	28.33	4.66	0.00	1.764
67	280 - 289 W	2	Lamps	36.07	4.46	0.00	1	39.93	4.66	0.00	1.012

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Line No.	(a) Description	(b) Billing Determinants		(c) Present				(d) Proposed			
				Non-Capacity		Capacity		Non-Capacity		Capacity	
				Rate	Energy	Energy	Revenue	Rate	Energy	Energy	Revenue
		Quantity	Units	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)
68	LED										
69	20 - 29 W	0	Lamps	15.91	4.46	0.00	0	15.50	4.66	0.00	0
70	30 - 39 W	3	Lamps	16.65	4.46	0.00	1	16.78	4.66	0.00	1
71	40 - 49 W	73	Lamps	17.39	4.46	0.00	16	18.07	4.66	0.00	16
72	50 - 59 W	22,280	Lamps	18.12	4.46	0.00	5,067	19.36	4.66	0.00	5,409
73	60 - 69 W	36,373	Lamps	19.29	4.46	0.00	8,848	20.66	4.66	0.00	9,467
74	70 - 79 W	607	Lamps	20.46	4.46	0.00	157	21.96	4.66	0.00	169
75	80 - 89 W	1,685	Lamps	21.63	4.46	0.00	463	23.26	4.66	0.00	498
76	90 - 99 W	1,509	Lamps	22.80	4.46	0.00	439	24.56	4.66	0.00	472
77	100 - 109 W	90	Lamps	23.97	4.46	0.00	28	25.86	4.66	0.00	30
78	110 - 119 W	3	Lamps	25.14	4.46	0.00	1	27.16	4.66	0.00	1
79	120 - 129 W	58	Lamps	26.31	4.46	0.00	20	28.46	4.66	0.00	21
80	130 - 139 W	21,218	Lamps	27.40	4.46	0.00	7,496	29.76	4.66	0.00	8,121
81	140 - 149 W	165	Lamps	28.27	4.46	0.00	60	30.88	4.66	0.00	66
82	150 - 159 W	400	Lamps	29.13	4.46	0.00	151	31.23	4.66	0.00	162
83	160 - 169 W	108	Lamps	30.00	4.46	0.00	42	32.33	4.66	0.00	45
84	170 - 179 W	53	Lamps	30.86	4.46	0.00	21	33.42	4.66	0.00	23
85	180 - 189 W	9	Lamps	31.73	4.46	0.00	4	34.51	4.66	0.00	4
86	190 - 199 W	0	Lamps	32.59	4.46	0.00	0	35.61	4.66	0.00	0
87	200 - 209 W	150	Lamps	33.46	4.46	0.00	66	36.70	4.66	0.00	72
88	210 - 219 W	35	Lamps	34.32	4.46	0.00	16	37.68	4.66	0.00	17
89	220 - 229 W	0	Lamps	34.61	4.46	0.00	0	38.01	4.66	0.00	0
90	230 - 239 W	699	Lamps	34.90	4.46	0.00	323	38.33	4.66	0.00	353
91	240 - 249 W	5	Lamps	35.74	4.46	0.00	2	39.26	4.66	0.00	3
92	250 - 259 W	11	Lamps	36.58	4.46	0.00	5	40.18	4.66	0.00	6
93	260 - 269 W	0	Lamps	37.41	4.46	0.00	0	41.10	4.66	0.00	0
94	270 - 279 W	0	Lamps	38.25	4.46	0.00	0	42.03	4.66	0.00	0
95	280 - 289 W	771	Lamps	39.09	4.46	0.00	401	42.95	4.66	0.00	439
96	290 - 299 W	14	Lamps	39.93	4.46	0.00	7	43.87	4.66	0.00	8
97	300 - 309 W	15	Lamps	40.77	4.46	0.00	8	44.80	4.66	0.00	9
98	310 - 319 W	0	Lamps	41.61	4.46	0.00	0	45.73	4.66	0.00	0
99	320 - 329 W	4	Lamps	42.45	4.46	0.00	2	46.65	4.66	0.00	2
100	330 - 339 W	0	Lamps	43.29	4.46	0.00	0	47.58	4.66	0.00	0
101	340 - 349 W	0	Lamps	44.12	4.46	0.00	0	48.50	4.66	0.00	0
102	350 - 359 W	0	Lamps	44.96	4.46	0.00	0	49.43	4.66	0.00	0
103	360 - 369 W	0	Lamps	45.80	4.46	0.00	0	50.35	4.66	0.00	0
104	370 - 379 W	0	Lamps	46.64	4.46	0.00	0	51.28	4.66	0.00	0
105	380 - 389 W	0	Lamps	47.48	4.46	0.00	0	52.21	4.66	0.00	0
106	390 - 399 W	0	Lamps	48.32	4.46	0.00	0	53.13	4.66	0.00	0
107	Subtotal	96,838	Lamps				27,316				29,428
108											
109	PSCR	37,920	MWh	0			0	\$ -			0
110											
111	Multiple Lamp Discount	1,445	Lamps	(\$12.24)			(18)	-12.24			(18)
112	Subtotal	96,838	Lamps				27,298				29,411
113	IRM	37,920	MWh	0.005140			195	0.005140			195
114	Nuclear Decomm.	37,920	MWh	0.000882			33	0.000882			33
115	Subtotal	96,838	Lamps				27,527				29,639
116											
117	Energy Optimization	558	Meters	\$5.50			37	\$ 5.50			37
118											
119	Total E1 - Option 1	37,920	MWh				27,564				29,676
120	Increase/Decrease (\$)										2,112

Line No.	(a) Description	(b) Billing Determinants		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				Present				Proposed			
		Quantity	Units	Rate (\$/luminaire/ mth)	Non-Capacity Energy (\$/kWh)	Capacity Energy (\$/kWh)	Revenue (\$000)	Rate (\$/luminaire/ mth)	Non-Capacity Energy (\$/kWh)	Capacity Energy (\$/kWh)	Revenue (\$000)
	Co. Owned Ornamental										
1	Mercury Vapor										
2	100 W	10	Lamps	32.48	4.46	0.00	4	32.40	4.66	0.00	4
3	175 W	830	Lamps	37.64	4.46	0.00	406	38.14	4.66	0.00	413
4	250 W	1	Lamps	45.55	4.46	0.00	1	46.51	4.66	0.00	1
5	400 W	418	Lamps	57.87	4.46	0.00	324	59.67	4.66	0.00	335
6	1,000 W	0	Lamps	118.04	4.46	0.00	0	123.26	4.66	0.00	0
7											
8	High Pressure Sodium Vapor										
9	70 W	73	Lamps	24.77	4.46	0.00	23	24.70	4.66	0.00	23
10	100 W	17,584	Lamps	28.06	4.46	0.00	6,351	27.98	4.66	0.00	6,354
11	150 W	445	Lamps	31.04	4.46	0.00	182	31.75	4.66	0.00	186
12	250 W	2,931	Lamps	38.42	4.46	0.00	1,513	39.84	4.66	0.00	1,571
13	360 W	0	Lamps	46.06	4.46	0.00	0	48.40	4.66	0.00	0
14	400 W	961	Lamps	48.83	4.46	0.00	644	51.51	4.66	0.00	679
15	1,000 W	2	Lamps	92.93	4.46	0.00	3	102.41	4.66	0.00	3
16											
17	Metal Halide										
18	70 W	195	Lamps	34.36	4.46	0.00	83	34.30	4.66	0.00	83
19	100 W	83	Lamps	36.37	4.46	0.00	38	36.29	4.66	0.00	38
20	150 W	14	Lamps	40.05	4.46	0.00	7	43.92	4.66	0.00	8
21	175 W	217	Lamps	40.52	4.46	0.00	114	40.37	4.66	0.00	114
22	250 W	264	Lamps	48.13	4.46	0.00	167	48.48	4.66	0.00	169
23	320 W	0	Lamps	53.97	4.46	0.00	0	55.79	4.66	0.00	0
24	400 W	228	Lamps	60.63	4.46	0.00	185	64.15	4.66	0.00	195
25	1,000 W	0	Lamps	110.60	4.46	0.00	0	126.86	4.66	0.00	0
26											
27	De-Energized										
28	Mercury Vapor	0									
29	100 W	0	Lamps	20.61	4.46	0.00	0	20.58	4.66	0.00	0.000
30	175 W	0	Lamps	24.55	4.46	0.00	0	24.87	4.66	0.00	0.000
31	250 W	0	Lamps	30.14	4.46	0.00	0	30.75	4.66	0.00	0.000
32	400 W	0	Lamps	38.93	4.46	0.00	0	40.07	4.66	0.00	0.000
33	1,000 W	0	Lamps	80.75	4.46	0.00	0	84.00	4.66	0.00	0.000
34											
35	LED										
36	60 - 69 W	27	Lamps	14.66	4.46	0.00	5	14.68	4.66	0.00	4.758
37											
38	High Pressure Sodium Vapor										
39	70 W	0	Lamps	15.75	4.46	0.00	0	15.72	4.66	0.00	0.000
40	100 W	0	Lamps	18.10	4.46	0.00	0	18.07	4.66	0.00	0.000
41	150 W	0	Lamps	20.49	4.46	0.00	0	20.95	4.66	0.00	0.000
42	250 W	17	Lamps	25.90	4.46	0.00	5	26.80	4.66	0.00	5.467
43	360 W	0	Lamps	31.55	4.46	0.00	0	33.00	4.66	0.00	0.000
44	400 W	0	Lamps	33.65	4.46	0.00	0	35.31	4.66	0.00	0.000
45	1,000 W	0	Lamps	66.05	4.46	0.00	0	71.87	4.66	0.00	0.000
46											
47	Dusk-Midnight										
48	Mercury Vapor										
49	100 W	0	Lamps	31.42	4.46	0.00	0	31.34	4.66	0.00	0.000
50	175 W	0	Lamps	35.78	4.46	0.00	0	36.28	4.66	0.00	0.000
51	250 W	0	Lamps	42.90	4.46	0.00	0	43.86	4.66	0.00	0.000
52	400 W	0	Lamps	53.63	4.46	0.00	0	55.43	4.66	0.00	0.000
53	1,000 W	0	Lamps	107.44	4.46	0.00	0	112.66	4.66	0.00	0.000
54											
55	High Pressure Sodium Vapor										
56	70 W	0	Lamps	24.03	4.46	0.00	0	23.96	4.66	0.00	0.000
57	100 W	0	Lamps	27.00	4.46	0.00	0	26.92	4.66	0.00	0.000
58	150 W	0	Lamps	29.45	4.46	0.00	0	30.16	4.66	0.00	0.000
59	250 W	0	Lamps	35.77	4.46	0.00	0	37.19	4.66	0.00	0.000
60	360 W	0	Lamps	42.24	4.46	0.00	0	44.58	4.66	0.00	0.000
61	400 W	0	Lamps	44.59	4.46	0.00	0	47.27	4.66	0.00	0.000
62	1,000 W	0	Lamps	82.33	4.46	0.00	0	91.81	4.66	0.00	0.000
	LED										
	130 - 139 W	21	Lamps	27.95	4.46	0.00	7	29.02	4.66	0.00	7.583

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[illegible]

Case No.: U-21534
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Schedule: F3 Revised
Witness: R. A. Bellini
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Line No.	(a) Description	(b) Billing Determinants	(c)	(d) Present	(e)	(f)	(g)	(h) Proposed	(i)	(j)	
				Non-Capacity	Capacity			Non-Capacity	Capacity		
		Load	Dist Energy	Energy	Energy	Revenue	Dist Energy	Energy	Energy	Revenue	
	Energy Only Service	Quantity	(¢/kWh)	(¢/kWh)	(¢/kWh)	(\$000)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(\$000)	
1	Mercury Vapor										
2	100 Watt	12	1	10.88	4.46	0.00	1	13.36	4.66	0.00	1
3	175 Watt	167	29	10.88	4.46	0.00	23	13.36	4.66	0.00	27
4	250 Watt	20	5	10.88	4.46	0.00	4	13.36	4.66	0.00	5
5	400 Watt	138	55	10.88	4.46	0.00	40	13.36	4.66	0.00	47
6	1,000 Watt		0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
7											
8	High Pressure Sodium Vapor										
9	70 Watt	293	21	10.88	4.46	0.00	18	13.36	4.66	0.00	21
10	100 Watt	8,829	883	10.88	4.46	0.00	768	13.36	4.66	0.00	902
11	150 Watt	1,669	250	10.88	4.46	0.00	215	13.36	4.66	0.00	253
12	250 Watt	986	247	10.88	4.46	0.00	194	13.36	4.66	0.00	228
13	310 Watt	28	9	10.88	4.46	0.00	7	13.36	4.66	0.00	8
14	360 Watt	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
15	400 Watt	423	169	10.88	4.46	0.00	127	13.36	4.66	0.00	149
16	1,000 Watt	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
17		0									
18	Metal Halide	0									
19	70 Watt	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
20	100 Watt	90	9	10.88	4.46	0.00	7	13.36	4.66	0.00	8
21	150 Watt	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
22	175 Watt	135	24	10.88	4.46	0.00	18	13.36	4.66	0.00	21
23	250 Watt	34	9	10.88	4.46	0.00	7	13.36	4.66	0.00	8
24	320 Watt	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
25	400 Watt	33	13	10.88	4.46	0.00	10	13.36	4.66	0.00	11
26	1,000 Watt	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
27	Energy Subtotal	12,857	1,724			1,437					1,689
28											
29	LED										
30	20 - 29 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
31	30 - 39 W	4,585	160	10.88	4.46	0.00	103	13.36	4.66	0.00	121
32	40 - 49 W	155	7	10.88	4.46	0.00	4	13.36	4.66	0.00	5
33	50 - 59 W	1,166	64	10.88	4.46	0.00	41	13.36	4.66	0.00	49
34	60 - 69 W	721	47	10.88	4.46	0.00	30	13.36	4.66	0.00	35
35	70 - 79 W	198	15	10.88	4.46	0.00	10	13.36	4.66	0.00	11
36	80 - 89 W	14,235	1,210	10.88	4.46	0.00	780	13.36	4.66	0.00	916
37	90 - 99 W	205	19	10.88	4.46	0.00	13	13.36	4.66	0.00	15
38	100 - 109 W	14,602	1,533	10.88	4.46	0.00	988	13.36	4.66	0.00	1,161
39	110 - 119 W	14,436	1,660	10.88	4.46	0.00	1,070	13.36	4.66	0.00	1,257
40	120 - 129 W	931	116	10.88	4.46	0.00	75	13.36	4.66	0.00	88
41	130 - 139 W	7,962	1,075	10.88	4.46	0.00	693	13.36	4.66	0.00	814
42	140 - 149 W	4	1	10.88	4.46	0.00	0	13.36	4.66	0.00	0
43	150 - 159 W	1,251	194	10.88	4.46	0.00	125	13.36	4.66	0.00	147
44	160 - 169 W	465	77	10.88	4.46	0.00	49	13.36	4.66	0.00	58
45	170 - 179 W	96	17	10.88	4.46	0.00	11	13.36	4.66	0.00	13
46	180 - 189 W	87	16	10.88	4.46	0.00	10	13.36	4.66	0.00	12
47	190 - 199 W	9	2	10.88	4.46	0.00	1	13.36	4.66	0.00	1
48	200 - 209 W	190	39	10.88	4.46	0.00	25	13.36	4.66	0.00	29
49	210 - 219 W	3,084	663	10.88	4.46	0.00	427	13.36	4.66	0.00	502
50	220 - 229 W	269	61	10.88	4.46	0.00	39	13.36	4.66	0.00	46
51	230 - 239 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
52	240 - 249 W	1	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
53	250 - 259 W	175	45	10.88	4.46	0.00	29	13.36	4.66	0.00	34
54	260 - 269 W	4,438	1,176	10.88	4.46	0.00	758	13.36	4.66	0.00	890
55	270 - 279 W	262	72	10.88	4.46	0.00	46	13.36	4.66	0.00	55

Line No.	(a) Description	(b) Billing Determinants	(c)	(d) Present	(e)	(f)	(g)	(h) Proposed	(i)	(j)	
				Present			Proposed				
				<u>Dist Energy</u>	<u>Non-Capacity</u> <u>Energy</u>	<u>Capacity</u> <u>Energy</u>	<u>Revenue</u>	<u>Dist Energy</u>	<u>Non-Capacity</u> <u>Energy</u>	<u>Capacity</u> <u>Energy</u>	<u>Revenue</u>
		<u>Quantity</u>	<u>Load</u> <u>(kW)</u>	<u>(¢/kWh)</u>	<u>(¢/kWh)</u>	<u>(¢/kWh)</u>	<u>(\$000)</u>	<u>(¢/kWh)</u>	<u>(¢/kWh)</u>	<u>(¢/kWh)</u>	<u>(\$000)</u>
56	<u>Energy Only Service</u>										
57	LED										
57	280 - 289 W	13	4	10.88	4.46	0.00	2	13.36	4.66	0.00	3
58	290 - 299 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
59	300 - 309 W	5	2	10.88	4.46	0.00	1	13.36	4.66	0.00	1
60	310 - 319 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
61	320 - 329 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
62	330 - 339 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
63	340 - 349 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
64	350 - 359 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
65	360 - 369 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
66	370 - 379 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
67	380 - 389 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
68	390 - 399 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
69	LED Subtotal	69,545	8,275				5,331				6,264
70											
71	PSCR	44,120	MWh	0			0	\$ -			0
72	Subtotal	82,402					6,768				7,952
73	IRM	44,120	MWh	0.005140			227	0.005140			227
74	Nuclear Decommissioning	44,120	MWh	0.000882			39	0.000882			39
75	Subtotal	44,120	MWh				7,034				8,218
76											
77	Energy Optimization	40	Meters	\$ 5.50			2.65	\$ 5.50			2.65
78											
79	Total E1 - Option III	44,120	MWh				7,036				8,221
80	Increase/Decrease (\$)										1,185
	Total E1 - Options I, II and III	123,056	MWh				63,859				67,751

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Schedule: F4

Witness: A. Willis

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DTE Electric Company
Case No. U-21534
Typical Bill Comparisons by Rate Schedule

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Non-Transmitting Meter - D1

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Present Rates and Current Surcharges:
Power Supply Charges:

Non-Capacity Charge **\$0.07809**

Capacity Charges:
First 17 KWH/Day **\$0.01128**
Excess **\$0.01626**

Power Supply Surcharges: **\$0.00000**
REPS **\$0.00**

Service Charge **\$8.50**
Distribution Charge: **\$0.08137**

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:
Power Supply Charges:

Non-Capacity Charge **\$0.06237**

Capacity Charges:
First 17 KWH/Day **\$0.02932**
Excess **\$0.04227**

Power Supply Surcharges: **\$0.00000**
REPS **\$0.00**

Service Charge: **\$8.50**
Distribution Charge: **\$0.09451**

Delivery Surcharges: \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	100	\$26.89	\$28.44	\$1.55	5.75%	28.44¢
2	120	\$30.39	\$32.25	\$1.86	6.10%	26.87¢
3	140	\$33.90	\$36.06	\$2.16	6.39%	25.76¢
4	160	\$37.40	\$39.87	\$2.47	6.61%	24.92¢
5	180	\$40.90	\$43.68	\$2.78	6.80%	24.27¢
6	200	\$44.40	\$47.50	\$3.09	6.96%	23.75¢
7	240	\$51.41	\$55.12	\$3.71	7.22%	22.97¢
8	280	\$58.41	\$62.74	\$4.33	7.41%	22.41¢
9	300	\$61.91	\$66.55	\$4.64	7.49%	22.18¢
10	350	\$70.67	\$76.08	\$5.41	7.66%	21.74¢
11	400	\$79.43	\$85.61	\$6.18	7.79%	21.40¢
12	450	\$88.18	\$95.14	\$6.96	7.89%	21.14¢
13	500	\$96.94	\$104.67	\$7.73	7.97%	20.93¢
14	550	\$105.89	\$114.71	\$8.82	8.33%	20.86¢
15	600	\$114.90	\$124.89	\$9.99	8.70%	20.82¢
16	650	\$123.90	\$135.07	\$11.16	9.01%	20.78¢
17	700	\$132.91	\$145.24	\$12.34	9.28%	20.75¢
18	750	\$141.91	\$155.42	\$13.51	9.52%	20.72¢
19	800	\$150.92	\$165.60	\$14.68	9.73%	20.70¢
20	850	\$159.92	\$175.77	\$15.85	9.91%	20.68¢
21	900	\$168.93	\$185.95	\$17.02	10.08%	20.66¢
22	950	\$177.93	\$196.12	\$18.19	10.23%	20.64¢
23	1,000	\$186.94	\$206.30	\$19.37	10.36%	20.63¢
24	1,100	\$204.94	\$226.65	\$21.71	10.59%	20.60¢
25	1,200	\$222.95	\$247.01	\$24.05	10.79%	20.58¢
26	1,300	\$240.96	\$267.36	\$26.39	10.95%	20.57¢
27	1,400	\$258.97	\$287.71	\$28.74	11.10%	20.55¢
28	1,500	\$276.98	\$308.06	\$31.08	11.22%	20.54¢
29	2,000	\$367.03	\$409.83	\$42.80	11.66%	20.49¢
30	2,750	\$502.10	\$562.47	\$60.37	12.02%	20.45¢
31	4,000	\$727.22	\$816.88	\$89.66	12.33%	20.42¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible Space-Conditioning Service Rate - D1.1 Residential
June thru October

Case No.: U-21534
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Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Non Capacity Charge \$0.06085

Capacity Charge \$0.01089

Power Supply Surcharges: \$0.00000

Distribution Charges:

Service Charge: \$1.95

Distribution Energy \$0.08137

Delivery Surcharges: \$0.004375

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non Capacity Charge \$0.04870

Capacity Charge \$0.02799

Power Supply Surcharges: \$0.00000

Distribution Charges:

Service Charge: \$1.95

Distribution Energy \$0.09451

Delivery Surcharges: \$0.004375

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase		(f) Proposed Unit Cost
				Amount	Percent	
1	100	\$17.70	\$19.51	\$1.81	10.22%	19.51¢
2	120	\$20.85	\$23.02	\$2.17	10.41%	19.18¢
3	140	\$24.00	\$26.53	\$2.53	10.55%	18.95¢
4	160	\$27.15	\$30.04	\$2.89	10.66%	18.78¢
5	180	\$30.30	\$33.55	\$3.26	10.75%	18.64¢
6	200	\$33.45	\$37.07	\$3.62	10.82%	18.53¢
7	240	\$39.75	\$44.09	\$4.34	10.92%	18.37¢
8	280	\$46.05	\$51.11	\$5.07	11.00%	18.25¢
9	300	\$49.20	\$54.62	\$5.43	11.03%	18.21¢
10	350	\$57.07	\$63.40	\$6.33	11.09%	18.11¢
11	400	\$64.94	\$72.18	\$7.24	11.14%	18.05¢
12	450	\$72.82	\$80.96	\$8.14	11.18%	17.99¢
13	500	\$80.69	\$89.74	\$9.05	11.21%	17.95¢
14	550	\$88.57	\$98.52	\$9.95	11.23%	17.91¢
15	600	\$96.44	\$107.30	\$10.85	11.25%	17.88¢
16	650	\$104.32	\$116.07	\$11.76	11.27%	17.86¢
17	700	\$112.19	\$124.85	\$12.66	11.29%	17.84¢
18	750	\$120.06	\$133.63	\$13.57	11.30%	17.82¢
19	800	\$127.94	\$142.41	\$14.47	11.31%	17.80¢
20	850	\$135.81	\$151.19	\$15.38	11.32%	17.79¢
21	900	\$143.69	\$159.97	\$16.28	11.33%	17.77¢
22	950	\$151.56	\$168.75	\$17.19	11.34%	17.76¢
23	1,000	\$159.44	\$177.53	\$18.09	11.35%	17.75¢
24	1,100	\$175.18	\$195.08	\$19.90	11.36%	17.73¢
25	1,200	\$190.93	\$212.64	\$21.71	11.37%	17.72¢
26	1,300	\$206.68	\$230.20	\$23.52	11.38%	17.71¢
27	1,400	\$222.43	\$247.76	\$25.33	11.39%	17.70¢
28	1,500	\$238.18	\$265.31	\$27.14	11.39%	17.69¢
29	2,000	\$316.92	\$353.10	\$36.18	11.42%	17.66¢
30	3,000	\$474.41	\$528.68	\$54.27	11.44%	17.62¢
31	4,000	\$631.89	\$704.25	\$72.36	11.45%	17.61¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible Space-Conditioning Service Rate - D1.1 Residential
November thru May

Case No.: U-21534
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Present Rates and Current Surcharges:

Power Supply Charges:

Non Capacity Charge \$0.06085

Capacity Charge \$0.00270

Power Supply Surcharges: \$0.00000

Distribution Charges:
Service Charge: \$0.00

Distribution Energy \$0.08137

Delivery Surcharges: \$0.004375

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non Capacity Charge \$0.04870

Capacity Charge \$0.00694

Power Supply Surcharges: \$0.00000

Distribution Charges:
Service Charge: \$0.00

Distribution Energy \$0.09451

Delivery Surcharges: \$0.004375

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase		(f) Proposed Unit Cost
				Amount	Percent	
1	100	\$14.93	\$15.45	\$0.52	3.50%	15.45¢
2	120	\$17.92	\$18.54	\$0.63	3.50%	15.45¢
3	140	\$20.90	\$21.63	\$0.73	3.50%	15.45¢
4	160	\$23.89	\$24.72	\$0.84	3.50%	15.45¢
5	180	\$26.87	\$27.81	\$0.94	3.50%	15.45¢
6	200	\$29.86	\$30.91	\$1.05	3.50%	15.45¢
7	240	\$35.83	\$37.09	\$1.26	3.50%	15.45¢
8	280	\$41.80	\$43.27	\$1.46	3.50%	15.45¢
9	300	\$44.79	\$46.36	\$1.57	3.50%	15.45¢
10	350	\$52.25	\$54.08	\$1.83	3.50%	15.45¢
11	400	\$59.72	\$61.81	\$2.09	3.50%	15.45¢
12	450	\$67.18	\$69.54	\$2.35	3.50%	15.45¢
13	500	\$74.65	\$77.26	\$2.61	3.50%	15.45¢
14	550	\$82.11	\$84.99	\$2.88	3.50%	15.45¢
15	600	\$89.58	\$92.72	\$3.14	3.50%	15.45¢
16	650	\$97.04	\$100.44	\$3.40	3.50%	15.45¢
17	700	\$104.51	\$108.17	\$3.66	3.50%	15.45¢
18	750	\$111.97	\$115.89	\$3.92	3.50%	15.45¢
19	800	\$119.44	\$123.62	\$4.18	3.50%	15.45¢
20	850	\$126.90	\$131.35	\$4.45	3.50%	15.45¢
21	900	\$134.37	\$139.07	\$4.71	3.50%	15.45¢
22	950	\$141.83	\$146.80	\$4.97	3.50%	15.45¢
23	1,000	\$149.30	\$154.53	\$5.23	3.50%	15.45¢
24	1,100	\$164.22	\$169.98	\$5.75	3.50%	15.45¢
25	1,200	\$179.15	\$185.43	\$6.28	3.50%	15.45¢
26	1,300	\$194.08	\$200.88	\$6.80	3.50%	15.45¢
27	1,400	\$209.01	\$216.34	\$7.32	3.50%	15.45¢
28	1,500	\$223.94	\$231.79	\$7.84	3.50%	15.45¢
29	2,000	\$298.59	\$309.05	\$10.46	3.50%	15.45¢
30	3,000	\$447.89	\$463.58	\$15.69	3.50%	15.45¢
31	4,000	\$597.18	\$618.10	\$20.92	3.50%	15.45¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Enhanced TOU - D1.2
June thru October

Case No.: U-21534
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
On-Peak Energy Rate: \$0.13949
Off-Peak Energy Rate: \$0.04696

Capacity Charges:
On-Peak Energy Rate: \$0.01690
Off-Peak Energy Rate: \$0.00569

Power Supply Surcharges: \$0.00000
REPS \$0.00

Distribution Charges:
Service Charge: \$8.50
Distribution Energy \$0.08137

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
On-Peak Energy Rate: \$0.11955
Off-Peak Energy Rate: \$0.04025

Capacity Charges:
On-Peak Energy Rate: \$0.04474
Off-Peak Energy Rate: \$0.01506

Power Supply Surcharges: \$0.00000
REPS \$0.00

Distribution Charges:
Service Charge: \$8.50
Distribution Energy \$0.09451

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Line No.	(a) Monthly kWh Use	(b) On-Peak Use	(c) Present Net Monthly Bill	(d) Proposed Net Monthly Bill	(e) Increase Amount	(f) Increase Percent	(g) Proposed Unit Cost
1	100	20%	\$25.29	\$26.98	\$1.68	6.66%	26.98¢
2	100	25%	\$25.81	\$27.52	\$1.71	6.63%	27.52¢
3	100	30%	\$26.33	\$28.07	\$1.74	6.60%	28.07¢
4							
5	200	20%	\$41.21	\$44.58	\$3.37	8.18%	22.29¢
6	200	25%	\$42.25	\$45.67	\$3.42	8.10%	22.83¢
7	200	30%	\$43.28	\$46.76	\$3.47	8.03%	23.38¢
8							
9	300	20%	\$57.12	\$62.18	\$5.05	8.85%	20.73¢
10	300	25%	\$58.68	\$63.81	\$5.13	8.75%	21.27¢
11	300	30%	\$60.24	\$65.45	\$5.21	8.65%	21.82¢
12							
13	400	20%	\$73.04	\$79.78	\$6.74	9.23%	19.94¢
14	400	25%	\$75.11	\$81.96	\$6.84	9.11%	20.49¢
15	400	30%	\$77.19	\$84.14	\$6.95	9.00%	21.03¢
16							
17	500	20%	\$88.95	\$97.38	\$8.42	9.47%	19.48¢
18	500	25%	\$91.55	\$100.10	\$8.56	9.35%	20.02¢
19	500	30%	\$94.14	\$102.82	\$8.69	9.23%	20.56¢
20							
21	600	20%	\$104.87	\$114.97	\$10.11	9.64%	19.16¢
22	600	25%	\$107.98	\$118.24	\$10.27	9.51%	19.71¢
23	600	30%	\$111.09	\$121.51	\$10.42	9.38%	20.25¢
24							
25	700	20%	\$120.78	\$132.57	\$11.79	9.76%	18.94¢
26	700	25%	\$124.41	\$136.39	\$11.98	9.63%	19.48¢
27	700	30%	\$128.04	\$140.20	\$12.16	9.50%	20.03¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Enhanced TOU - D1.2
June thru October

Case No.: U-21534

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Witness: A. Willis

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Monthly	On-Peak	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
28	800	20%	\$136.69	\$150.17	\$13.48	9.86%	18.77¢
29	800	25%	\$140.84	\$154.53	\$13.69	9.72%	19.32¢
30	800	30%	\$144.99	\$158.89	\$13.90	9.58%	19.86¢
31							
32	1,000	20%	\$168.52	\$185.37	\$16.85	10.00%	18.54¢
33	1,000	25%	\$173.71	\$190.82	\$17.11	9.85%	19.08¢
34	1,000	30%	\$178.90	\$196.27	\$17.37	9.71%	19.63¢
35							
36	1,100	20%	\$184.44	\$202.97	\$18.53	10.05%	18.45¢
37	1,100	25%	\$190.14	\$208.96	\$18.82	9.90%	19.00¢
38	1,100	30%	\$195.85	\$214.96	\$19.11	9.76%	19.54¢
39							
40	1,200	20%	\$200.35	\$220.57	\$20.22	10.09%	18.38¢
41	1,200	25%	\$206.58	\$227.11	\$20.53	9.94%	18.93¢
42	1,200	30%	\$212.80	\$233.65	\$20.85	9.80%	19.47¢
43							
44	1,300	20%	\$216.27	\$238.17	\$21.90	10.13%	18.32¢
45	1,300	25%	\$223.01	\$245.25	\$22.24	9.97%	18.87¢
46	1,300	30%	\$229.75	\$252.34	\$22.58	9.83%	19.41¢
47							
48	1,400	20%	\$232.18	\$255.77	\$23.59	10.16%	18.27¢
49	1,400	25%	\$239.44	\$263.40	\$23.95	10.00%	18.81¢
50	1,400	30%	\$246.70	\$271.02	\$24.32	9.86%	19.36¢
51							
52	1,500	20%	\$248.09	\$273.37	\$25.27	10.19%	18.22¢
53	1,500	25%	\$255.88	\$281.54	\$25.67	10.03%	18.77¢
54	1,500	30%	\$263.66	\$289.71	\$26.06	9.88%	19.31¢
55							
56	2,000	20%	\$327.67	\$361.36	\$33.70	10.28%	18.07¢
57	2,000	25%	\$338.04	\$372.26	\$34.22	10.12%	18.61¢
58	2,000	30%	\$348.41	\$383.16	\$34.74	9.97%	19.16¢
59							
60	3,000	20%	\$486.81	\$537.35	\$50.54	10.38%	17.91¢
61	3,000	25%	\$502.37	\$553.70	\$51.33	10.22%	18.46¢
62	3,000	30%	\$517.93	\$570.05	\$52.12	10.06%	19.00¢
63							
64	4,000	20%	\$645.95	\$713.34	\$67.39	10.43%	17.83¢
65	4,000	25%	\$666.70	\$735.14	\$68.44	10.27%	18.38¢
66	4,000	30%	\$687.45	\$756.94	\$69.49	10.11%	18.92¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Enhanced TOU - D1.2
November thru May

Case No.: U-21534

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Witness: A. Willis

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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
On-Peak Energy Rate: \$0.11783
Off-Peak Energy Rate: \$0.04512

Capacity Charges:
On-Peak Energy Rate: \$0.01427
Off-Peak Energy Rate: \$0.00547

Power Supply Surcharges: \$0.00000
REPS \$0.00

Distribution Charges:
Service Charge: \$8.50

Distribution Energy \$0.08137

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
On-Peak Energy Rate: \$0.10098
Off-Peak Energy Rate: \$0.03867

Capacity Charges:
On-Peak Energy Rate: \$0.03779
Off-Peak Energy Rate: \$0.01447

Power Supply Surcharges: \$0.00000
REPS \$0.00

Distribution Charges:
Service Charge: \$8.50

Distribution Energy \$0.09451

Delivery Surcharges: \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kWh Use	On-Peak Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
					Amount	Percent	
1	100	20%	\$24.64	\$26.30	\$1.65	6.70%	26.30¢
2	100	25%	\$25.05	\$26.72	\$1.67	6.67%	26.72¢
3	100	30%	\$25.46	\$27.15	\$1.69	6.65%	27.15¢
4							
5	200	20%	\$39.91	\$43.21	\$3.30	8.28%	21.61¢
6	200	25%	\$40.72	\$44.07	\$3.34	8.21%	22.03¢
7	200	30%	\$41.54	\$44.92	\$3.39	8.15%	22.46¢
8							
9	300	20%	\$55.17	\$60.13	\$4.95	8.98%	20.04¢
10	300	25%	\$56.39	\$61.41	\$5.02	8.89%	20.47¢
11	300	30%	\$57.62	\$62.69	\$5.08	8.81%	20.90¢
12							
13	400	20%	\$70.43	\$77.04	\$6.61	9.38%	19.26¢
14	400	25%	\$72.07	\$78.75	\$6.69	9.28%	19.69¢
15	400	30%	\$73.70	\$80.47	\$6.77	9.19%	20.12¢
16							
17	500	20%	\$85.70	\$93.96	\$8.26	9.63%	18.79¢
18	500	25%	\$87.74	\$96.10	\$8.36	9.53%	19.22¢
19	500	30%	\$89.77	\$98.24	\$8.46	9.43%	19.65¢
20							
21	600	20%	\$100.96	\$110.87	\$9.91	9.81%	18.48¢
22	600	25%	\$103.41	\$113.44	\$10.03	9.70%	18.91¢
23	600	30%	\$105.85	\$116.01	\$10.16	9.59%	19.33¢
24							
25	700	20%	\$116.23	\$127.79	\$11.56	9.95%	18.26¢
26	700	25%	\$119.08	\$130.78	\$11.70	9.83%	18.68¢
27	700	30%	\$121.93	\$133.78	\$11.85	9.72%	19.11¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Enhanced TOU - D1.2
November thru May

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Monthly	On-Peak	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
28	800	20%	\$131.49	\$144.70	\$13.21	10.05%	18.09¢
29	800	25%	\$134.75	\$148.13	\$13.38	9.93%	18.52¢
30	800	30%	\$138.01	\$151.55	\$13.54	9.81%	18.94¢
31							
32	1,000	20%	\$162.02	\$178.53	\$16.51	10.19%	17.85¢
33	1,000	25%	\$166.09	\$182.81	\$16.72	10.07%	18.28¢
34	1,000	30%	\$170.17	\$187.09	\$16.93	9.95%	18.71¢
35							
36	1,100	20%	\$177.28	\$195.45	\$18.17	10.25%	17.77¢
37	1,100	25%	\$181.76	\$200.16	\$18.39	10.12%	18.20¢
38	1,100	30%	\$186.25	\$204.87	\$18.62	10.00%	18.62¢
39							
40	1,200	20%	\$192.54	\$212.36	\$19.82	10.29%	17.70¢
41	1,200	25%	\$197.44	\$217.50	\$20.06	10.16%	18.12¢
42	1,200	30%	\$202.33	\$222.64	\$20.31	10.04%	18.55¢
43							
44	1,300	20%	\$207.81	\$229.28	\$21.47	10.33%	17.64¢
45	1,300	25%	\$213.11	\$234.84	\$21.74	10.20%	18.06¢
46	1,300	30%	\$218.40	\$240.41	\$22.00	10.07%	18.49¢
47							
48	1,400	20%	\$223.07	\$246.19	\$23.12	10.36%	17.59¢
49	1,400	25%	\$228.78	\$252.19	\$23.41	10.23%	18.01¢
50	1,400	30%	\$234.48	\$258.18	\$23.70	10.11%	18.44¢
51							
52	1,500	20%	\$238.34	\$263.11	\$24.77	10.39%	17.54¢
53	1,500	25%	\$244.45	\$269.53	\$25.08	10.26%	17.97¢
54	1,500	30%	\$250.56	\$275.95	\$25.39	10.13%	18.40¢
55							
56	2,000	20%	\$314.65	\$347.68	\$33.03	10.50%	17.38¢
57	2,000	25%	\$322.81	\$356.25	\$33.44	10.36%	17.81¢
58	2,000	30%	\$330.96	\$364.81	\$33.85	10.23%	18.24¢
59							
60	3,000	20%	\$467.29	\$516.83	\$49.54	10.60%	17.23
61	3,000	25%	\$479.52	\$529.68	\$50.16	10.46%	17.66
62	3,000	30%	\$491.74	\$542.52	\$50.78	10.33%	18.08
63							
64	4,000	20%	\$619.93	\$685.98	\$66.06	10.66%	17.15
65	4,000	25%	\$636.23	\$703.11	\$66.88	10.51%	17.58
66	4,000	30%	\$652.53	\$720.24	\$67.70	10.38%	18.01

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Special Low Income Pilot - D1.6

Case No.: U-21534

Exhibit: A-16

Schedule: F4

Witness: A. Willis

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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge: \$0.07809

Capacity Charges:

First 17 KWH/Day \$0.01128

Excess \$0.01626

Power Supply Surcharges: **\$0.00000**

REPS **\$0.00**

Service Charge \$8.50

Distribution Charge: \$0.08137

Income Assistance **(\$40.00)**

Delivery Surcharges: \$0.004375

LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge: \$0.06237

Capacity Charges:

First 17 KWH/Day \$0.02932

Excess \$0.04227

Power Supply Surcharges: **\$0.00000**

REPS **\$0.00**

Service Charge: \$8.50

Distribution Charge: \$0.09451

Income Assistance **(\$50.00)**

Delivery Surcharges: \$0.004375

LIEAF \$0.88

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase		(e) Percent	(f) Proposed Unit Cost
				Amount			
1	300	\$21.91	\$16.55	-\$5.36		-24.47%	5.52¢
2	350	\$30.67	\$26.08	-\$4.59		-14.96%	7.45¢
3	400	\$39.43	\$35.61	-\$3.82		-9.68%	8.90¢
4	450	\$48.18	\$45.14	-\$3.04		-6.32%	10.03¢
5	500	\$56.94	\$54.67	-\$2.27		-3.99%	10.93¢
6	550	\$65.89	\$64.71	-\$1.18		-1.79%	11.77¢
7	600	\$74.90	\$74.89	-\$0.01		-0.01%	12.48¢
8	650	\$83.90	\$85.07	\$1.16		1.39%	13.09¢
9	700	\$92.91	\$95.24	\$2.34		2.51%	13.61¢
10	750	\$101.91	\$105.42	\$3.51		3.44%	14.06¢
11	800	\$110.92	\$115.60	\$4.68		4.22%	14.45¢
12	850	\$119.92	\$125.77	\$5.85		4.88%	14.80¢
13	900	\$128.93	\$135.95	\$7.02		5.45%	15.11¢
14	950	\$137.93	\$146.12	\$8.19		5.94%	15.38¢
15	1,000	\$146.94	\$156.30	\$9.37		6.37%	15.63¢
16	1,100	\$164.94	\$176.65	\$11.71		7.10%	16.06¢
17	1,200	\$182.95	\$197.01	\$14.05		7.68%	16.42¢
18	1,300	\$200.96	\$217.36	\$16.39		8.16%	16.72¢
19	1,400	\$218.97	\$237.71	\$18.74		8.56%	16.98¢
20	1,500	\$236.98	\$258.06	\$21.08		8.90%	17.20¢
21	2,000	\$327.03	\$359.83	\$32.80		10.03%	17.99¢
22	2,750	\$462.10	\$512.47	\$50.37		10.90%	18.64¢
23	4,000	\$687.22	\$766.88	\$79.66		11.59%	19.17¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Geothermal Time of Day Rate - D1.7 Residential
June thru September

Case No.: U-21534
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Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge: \$0.04582

Capacity Charges:

On-Peak Energy Rate \$0.04248

Off-Peak Energy Rate \$0.00001

Power Supply Surcharges \$0.00000

Distribution Charges

Service Charge \$2.01

Distribution Energy \$0.08137

Delivery Surcharges \$0.004375

Proposed Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge:

On-Peak Energy Rate \$0.09310

Off-Peak Energy Rate \$0.03084

Capacity Charges:

On-Peak Energy Rate \$0.05086

Off-Peak Energy Rate \$0.01685

Power Supply Surcharges \$0.00000

Distribution Charges

Service Charge \$2.01

Distribution Energy \$0.09451

Delivery Surcharges \$0.004375

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kWh Use	On-Peak Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
					Amount	Percent	
1	100	20%	\$16.02	\$18.59	\$2.58	16.08%	18.59¢
2	100	25%	\$16.23	\$19.07	\$2.85	17.53%	19.07¢
3	100	30%	\$16.44	\$19.56	\$3.11	18.94%	19.56¢
4							
5	200	20%	\$30.02	\$35.18	\$5.15	17.16%	17.59¢
6	200	25%	\$30.45	\$36.14	\$5.69	18.69%	18.07¢
7	200	30%	\$30.87	\$37.10	\$6.23	20.17%	18.55¢
8							
9	300	20%	\$44.03	\$51.76	\$7.73	17.55%	17.25¢
10	300	25%	\$44.67	\$53.20	\$8.54	19.11%	17.73¢
11	300	30%	\$45.30	\$54.65	\$9.34	20.62%	18.22¢
12							
13	400	20%	\$58.04	\$68.34	\$10.30	17.75%	17.09¢
14	400	25%	\$58.89	\$70.27	\$11.38	19.33%	17.57¢
15	400	30%	\$59.74	\$72.19	\$12.46	20.85%	18.05¢
16							
17	500	20%	\$72.04	\$84.92	\$12.88	17.88%	16.98¢
18	500	25%	\$73.11	\$87.33	\$14.23	19.46%	17.47¢
19	500	30%	\$74.17	\$89.74	\$15.57	20.99%	17.95¢
20							
21	600	20%	\$86.05	\$101.51	\$15.46	17.96%	16.92¢
22	600	25%	\$87.33	\$104.40	\$17.07	19.55%	17.40¢
23	600	30%	\$88.60	\$107.28	\$18.68	21.09%	17.88¢
24							
25	700	20%	\$100.06	\$118.09	\$18.03	18.02%	16.87¢
26	700	25%	\$101.54	\$121.46	\$19.92	19.61%	17.35¢
27	700	30%	\$103.03	\$124.83	\$21.80	21.16%	17.83¢
28							
29	800	20%	\$114.07	\$134.67	\$20.61	18.07%	16.83¢
30	800	25%	\$115.76	\$138.52	\$22.76	19.66%	17.32¢
31	800	30%	\$117.46	\$142.37	\$24.91	21.21%	17.80¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Geothermal Time of Day Rate - D1.7 Residential
June thru September

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Monthly	On-Peak	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
32	1,000	20%	\$142.08	\$167.84	\$25.76	18.13%	16.78¢
33	1,000	25%	\$144.20	\$172.65	\$28.45	19.73%	17.27¢
34	1,000	30%	\$146.33	\$177.47	\$31.14	21.28%	17.75¢
35							
36	1,100	20%	\$156.09	\$184.42	\$28.34	18.15%	16.77¢
37	1,100	25%	\$158.42	\$189.72	\$31.30	19.75%	17.25¢
38	1,100	30%	\$160.76	\$195.01	\$34.25	21.31%	17.73¢
39							
40	1,200	20%	\$170.09	\$201.00	\$30.91	18.17%	16.75¢
41	1,200	25%	\$172.64	\$206.78	\$34.14	19.78%	17.23¢
42	1,200	30%	\$175.19	\$212.56	\$37.37	21.33%	17.71¢
43							
44	1,300	20%	\$184.10	\$217.59	\$33.49	18.19%	16.74¢
45	1,300	25%	\$186.86	\$223.85	\$36.99	19.79%	17.22¢
46	1,300	30%	\$189.62	\$230.10	\$40.48	21.35%	17.70¢
47							
48	1,400	20%	\$198.11	\$234.17	\$36.06	18.20%	16.73¢
49	1,400	25%	\$201.08	\$240.91	\$39.83	19.81%	17.21¢
50	1,400	30%	\$204.05	\$247.65	\$43.60	21.37%	17.69¢
51							
52	1,500	20%	\$212.11	\$250.75	\$38.64	18.22%	16.72¢
53	1,500	25%	\$215.30	\$257.97	\$42.68	19.82%	17.20¢
54	1,500	30%	\$218.48	\$265.19	\$46.71	21.38%	17.68¢
55							
56	2,000	20%	\$282.15	\$333.67	\$51.52	18.26%	16.68¢
57	2,000	25%	\$286.40	\$343.30	\$56.90	19.87%	17.16¢
58	2,000	30%	\$290.64	\$352.92	\$62.28	21.43%	17.65¢
59							
60	3,000	20%	\$422.22	\$499.50	\$77.28	18.30%	16.65¢
61	3,000	25%	\$428.59	\$513.94	\$85.35	19.91%	17.13¢
62	3,000	30%	\$434.96	\$528.38	\$93.42	21.48%	17.61¢
63							
64	4,000	20%	\$562.29	\$665.33	\$103.04	18.33%	16.63¢
65	4,000	25%	\$570.78	\$684.58	\$113.80	19.94%	17.11¢
66	4,000	30%	\$579.27	\$703.83	\$124.56	21.50%	17.60¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Geothermal Time of Day Rate - D1.7 Residential
October thru May

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Present Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge: 0.04582
On-Peak Energy Rate
Off-Peak Energy Rate

Capacity Charges:
On-Peak Energy Rate \$0.01717
Off-Peak Energy Rate \$0.00369

Power Supply Surcharges \$0.00000

Distribution Charges

Service Charge \$2.01
Distribution Energy \$0.08137

Delivery Surcharges \$0.004375

Proposed Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge:
On-Peak Energy Rate \$0.04023
Off-Peak Energy Rate \$0.03161

Capacity Charges:
On-Peak Energy Rate \$0.02197
Off-Peak Energy Rate \$0.01727

Power Supply Surcharges \$0.00000

Distribution Charges

Service Charge \$2.01
Distribution Energy \$0.09451

Delivery Surcharges \$0.004375

Line No.	(a) Monthly kWh Use	(b) On-Peak Use	(c) Present Net Monthly Bill	(d) Proposed Net Monthly Bill	(e) Increase Amount	(f) Increase Percent	(g) Proposed Unit Cost
1	100	20%	\$15.81	\$17.05	\$1.25	7.89%	17.05¢
2	100	25%	\$15.87	\$17.12	\$1.25	7.86%	17.12¢
3	100	30%	\$15.94	\$17.19	\$1.25	7.82%	17.19¢
4							
5	200	20%	\$29.60	\$32.10	\$2.50	8.43%	16.05¢
6	200	25%	\$29.74	\$32.23	\$2.49	8.39%	16.11¢
7	200	30%	\$29.87	\$32.36	\$2.49	8.34%	16.18¢
8							
9	300	20%	\$43.40	\$47.14	\$3.74	8.63%	15.71¢
10	300	25%	\$43.60	\$47.34	\$3.74	8.58%	15.78¢
11	300	30%	\$43.80	\$47.54	\$3.74	8.54%	15.85¢
12							
13	400	20%	\$57.19	\$62.18	\$4.99	8.73%	15.55¢
14	400	25%	\$57.46	\$62.45	\$4.99	8.68%	15.61¢
15	400	30%	\$57.73	\$62.71	\$4.98	8.63%	15.68¢
16							
17	500	20%	\$70.99	\$77.22	\$6.24	8.79%	15.44¢
18	500	25%	\$71.32	\$77.56	\$6.24	8.74%	15.51¢
19	500	30%	\$71.66	\$77.89	\$6.23	8.70%	15.58¢
20							
21	600	20%	\$84.78	\$92.27	\$7.49	8.83%	15.38¢
22	600	25%	\$85.19	\$92.67	\$7.48	8.78%	15.44¢
23	600	30%	\$85.59	\$93.07	\$7.48	8.74%	15.51¢
24							
25	700	20%	\$98.58	\$107.31	\$8.73	8.86%	15.33¢
26	700	25%	\$99.05	\$107.78	\$8.73	8.81%	15.40¢
27	700	30%	\$99.52	\$108.24	\$8.72	8.77%	15.46¢
28							
29	800	20%	\$112.37	\$122.35	\$9.98	8.88%	15.29¢
30	800	25%	\$112.91	\$122.89	\$9.98	8.84%	15.36¢
31	800	30%	\$113.45	\$123.42	\$9.97	8.79%	15.43¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Geothermal Time of Day Rate - D1.7 Residential
October thru May

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Monthly	On-Peak	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
32	1,000	20%	\$139.96	\$152.44	\$12.48	8.92%	15.24¢
33	1,000	25%	\$140.64	\$153.11	\$12.47	8.87%	15.31¢
34	1,000	30%	\$141.31	\$153.77	\$12.46	8.82%	15.38¢
35							
36	1,100	20%	\$153.76	\$167.48	\$13.73	8.93%	15.23¢
37	1,100	25%	\$154.50	\$168.21	\$13.72	8.88%	15.29¢
38	1,100	30%	\$155.24	\$168.95	\$13.71	8.83%	15.36¢
39							
40	1,200	20%	\$167.55	\$182.52	\$14.97	8.94%	15.21¢
41	1,200	25%	\$168.36	\$183.32	\$14.96	8.89%	15.28¢
42	1,200	30%	\$169.17	\$184.12	\$14.95	8.84%	15.34¢
43							
44	1,300	20%	\$181.35	\$197.57	\$16.22	8.94%	15.20¢
45	1,300	25%	\$182.22	\$198.43	\$16.21	8.90%	15.26¢
46	1,300	30%	\$183.10	\$199.30	\$16.20	8.85%	15.33¢
47							
48	1,400	20%	\$195.14	\$212.61	\$17.47	8.95%	15.19¢
49	1,400	25%	\$196.09	\$213.54	\$17.46	8.90%	15.25¢
50	1,400	30%	\$197.03	\$214.48	\$17.45	8.85%	15.32¢
51							
52	1,500	20%	\$208.94	\$227.65	\$18.72	8.96%	15.18¢
53	1,500	25%	\$209.95	\$228.65	\$18.71	8.91%	15.24¢
54	1,500	30%	\$210.96	\$229.65	\$18.69	8.86%	15.31¢
55							
56	2,000	20%	\$277.91	\$302.87	\$24.96	8.98%	15.14¢
57	2,000	25%	\$279.26	\$304.20	\$24.94	8.93%	15.21¢
58	2,000	30%	\$280.61	\$305.53	\$24.92	8.88%	15.28¢
59							
60	3,000	20%	\$415.86	\$453.30	\$37.43	9.00%	15.11¢
61	3,000	25%	\$417.89	\$455.30	\$37.41	8.95%	15.18¢
62	3,000	30%	\$419.91	\$457.29	\$37.39	8.90%	15.24¢
63							
64	4,000	20%	\$553.81	\$603.73	\$49.91	9.01%	15.09¢
65	4,000	25%	\$556.51	\$606.39	\$49.88	8.96%	15.16¢
66	4,000	30%	\$559.21	\$609.05	\$49.85	8.91%	15.23¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Dynamic Peak Pricing - D1.8

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Present Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge:

Off-Peak Energy Rate	\$0.03940
Mid-Peak Energy Rate	\$0.07635
On-Peak Energy Rate	\$0.14747
Critical Peak Rate	\$0.14747

Capacity Charges:

Off-Peak Energy Rate	\$0.00590
Mid-Peak Energy Rate	\$0.01144
On-Peak Energy Rate	\$0.02067
Critical Peak Rate	\$0.80253

Power Supply Surcharges
REPS

\$0.00000
\$0.00

Distribution Charges

Service Charge	\$8.50
Distribution Energy	\$0.08137

Delivery Surcharges
LIEAF

\$0.004375
\$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge:

Off-Peak Energy Rate	\$0.03098
Mid-Peak Energy Rate	\$0.06004
On-Peak Energy Rate	\$0.11702
Critical Peak Rate	\$0.11702

Capacity Charges:

Off-Peak Energy Rate	\$0.01678
Mid-Peak Energy Rate	\$0.03252
On-Peak Energy Rate	\$0.06229
Critical Peak Rate	\$0.83298

Power Supply Surcharges
REPS

\$0.00000
\$0.00

Distribution Charges

Service Charge	\$8.50
Distribution Energy	\$0.09451

Delivery Surcharges
LIEAF

\$0.004375
\$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	100	\$25.61	\$27.36	\$1.75	6.85%	27.36¢
2	120	\$28.85	\$30.96	\$2.10	7.29%	25.80¢
3	160	\$35.35	\$38.15	\$2.81	7.94%	23.85¢
4	180	\$38.59	\$41.75	\$3.16	8.18%	23.19¢
5	200	\$41.84	\$45.35	\$3.51	8.38%	22.67¢
6	240	\$48.33	\$52.54	\$4.21	8.71%	21.89¢
7	280	\$54.82	\$59.73	\$4.91	8.96%	21.33¢
8	300	\$58.07	\$63.33	\$5.26	9.06%	21.11¢
9	350	\$66.18	\$72.32	\$6.14	9.28%	20.66¢
10	400	\$74.29	\$81.31	\$7.02	9.44%	20.33¢
11	450	\$82.41	\$90.30	\$7.89	9.58%	20.07¢
12	500	\$90.52	\$99.29	\$8.77	9.69%	19.86¢
13	550	\$98.64	\$108.28	\$9.65	9.78%	19.69¢
14	600	\$106.75	\$117.28	\$10.52	9.86%	19.55¢
15	650	\$114.87	\$126.27	\$11.40	9.93%	19.43¢
16	700	\$122.98	\$135.26	\$12.28	9.98%	19.32¢
17	750	\$131.09	\$144.25	\$13.15	10.03%	19.23¢
18	800	\$139.21	\$153.24	\$14.03	10.08%	19.16¢
19	850	\$147.32	\$162.23	\$14.91	10.12%	19.09¢
20	900	\$155.44	\$171.22	\$15.79	10.16%	19.02¢
21	950	\$163.55	\$180.21	\$16.66	10.19%	18.97¢
22	1,000	\$171.67	\$189.21	\$17.54	10.22%	18.92¢
23	1,100	\$187.89	\$207.19	\$19.29	10.27%	18.84¢
24	1,200	\$204.12	\$225.17	\$21.05	10.31%	18.76¢
25	1,300	\$220.35	\$243.15	\$22.80	10.35%	18.70¢
26	1,400	\$236.58	\$261.14	\$24.56	10.38%	18.65¢
27	1,500	\$252.81	\$279.12	\$26.31	10.41%	18.61¢
28	2,000	\$333.95	\$369.03	\$35.08	10.50%	18.45¢
29	3,000	\$496.24	\$548.86	\$52.62	10.60%	18.30¢
30	4,000	\$658.52	\$728.68	\$70.16	10.65%	18.22¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Electric Vehicle Rate - D1.9

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Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges
Non-Capacity Charges
 On-Peak Energy Rate \$0.14635
 Off-Peak Energy Rate \$0.03657
Capacity Charges:
 On-Peak Energy Rate \$0.02470
 Off-Peak Energy Rate \$0.00618

Power Supply Surcharges \$0.00000

Distribution Charges
Service Charge \$1.95
Distribution Energy \$0.08137

Delivery Surcharges \$0.004375

Proposed Rates and Current Surcharges:

Power Supply Charges
Non-Capacity Charges
 On-Peak Energy Rate \$0.11700
 Off-Peak Energy Rate \$0.02924
Capacity Charges:
 On-Peak Energy Rate \$0.06387
 Off-Peak Energy Rate \$0.01598

Power Supply Surcharges \$0.00000

Distribution Charges
Service Charge \$1.95
Distribution Energy \$0.09451

Delivery Surcharges \$0.004375

Line No.	(a) Monthly kWh Use	(b) On-Peak Use	(c) Present Net Monthly Bill	(d) Proposed Net Monthly Bill	(e) Increase		(f)	(g) Proposed Unit Cost
					Amount	Percent		
1	100	20%	\$17.37	\$19.07	\$1.71	9.84%		19.07¢
2	100	25%	\$18.01	\$19.75	\$1.74	9.69%		19.75¢
3	100	30%	\$18.65	\$20.43	\$1.78	9.55%		20.43¢
4								
5	200	20%	\$32.78	\$36.20	\$3.42	10.42%		18.10¢
6	200	25%	\$34.06	\$37.55	\$3.49	10.24%		18.78¢
7	200	30%	\$35.35	\$38.91	\$3.56	10.08%		19.46¢
8								
9	300	20%	\$48.20	\$53.32	\$5.12	10.63%		17.77¢
10	300	25%	\$50.12	\$55.36	\$5.23	10.44%		18.45¢
11	300	30%	\$52.05	\$57.39	\$5.34	10.27%		19.13¢
12								
13	400	20%	\$63.61	\$70.44	\$6.83	10.74%		17.61¢
14	400	25%	\$66.18	\$73.16	\$6.98	10.55%		18.29¢
15	400	30%	\$68.74	\$75.87	\$7.13	10.37%		18.97¢
16								
17	500	20%	\$79.03	\$87.57	\$8.54	10.81%		17.51¢
18	500	25%	\$82.24	\$90.96	\$8.72	10.61%		18.19¢
19	500	30%	\$85.44	\$94.35	\$8.91	10.43%		18.87¢
20								
21	600	20%	\$94.44	\$104.69	\$10.25	10.85%		17.45¢
22	600	25%	\$98.29	\$108.76	\$10.47	10.65%		18.13¢
23	600	30%	\$102.14	\$112.83	\$10.69	10.46%		18.81¢
24								
25	700	20%	\$109.86	\$121.81	\$11.96	10.88%		17.40¢
26	700	25%	\$114.35	\$126.56	\$12.21	10.68%		18.08¢
27	700	30%	\$118.84	\$131.31	\$12.47	10.49%		18.76¢
28								
29	800	20%	\$125.27	\$138.94	\$13.66	10.91%		17.37¢
30	800	25%	\$130.41	\$144.36	\$13.96	10.70%		18.05¢
31	800	30%	\$135.54	\$149.79	\$14.25	10.52%		18.72¢
32								
33	1,000	20%	\$156.11	\$173.19	\$17.08	10.94%		17.32¢
34	1,000	25%	\$162.52	\$179.97	\$17.45	10.74%		18.00¢
35	1,000	30%	\$168.94	\$186.75	\$17.82	10.55%		18.68¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Standard TOU - D1.11
June Thru September

Case No.: U-21534
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Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
June-Sept On Peak \$0.12201
June-Sept Off Peak \$0.07354

Capacity Charges:
June-Sept On Peak \$0.02060
June-Sept Off Peak \$0.01241

Power Supply Surcharges: \$0.00000
REPS \$0.00000

Service Charge: \$8.50
Distribution Charge: \$0.08137

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
June-Sept On Peak \$0.09748
June-Sept Off Peak \$0.05873

Capacity Charges:
June-Sept On Peak \$0.05325
June-Sept Off Peak \$0.03208

Power Supply Surcharges: \$0.00000
REPS \$0.00

Service Charge: \$8.50
Distribution Charge: \$0.09451

Delivery Surcharges: \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	100	\$27.48	\$29.33	\$1.85	6.75%	29.33¢
2	120	\$31.10	\$33.32	\$2.22	7.15%	27.77¢
3	140	\$34.72	\$37.31	\$2.59	7.47%	26.65¢
4	160	\$38.33	\$41.30	\$2.97	7.74%	25.81¢
5	180	\$41.95	\$45.29	\$3.34	7.95%	25.16¢
6	200	\$45.57	\$49.28	\$3.71	8.13%	24.64¢
7	240	\$52.81	\$57.26	\$4.45	8.42%	23.86¢
8	280	\$60.05	\$65.24	\$5.19	8.64%	23.30¢
9	300	\$63.67	\$69.23	\$5.56	8.73%	23.08¢
10	350	\$72.72	\$79.20	\$6.49	8.92%	22.63¢
11	400	\$81.77	\$89.18	\$7.41	9.07%	22.29¢
12	450	\$90.81	\$99.15	\$8.34	9.18%	22.03¢
13	500	\$99.86	\$109.13	\$9.27	9.28%	21.83¢
14	550	\$108.91	\$119.10	\$10.19	9.36%	21.66¢
15	600	\$117.96	\$129.08	\$11.12	9.43%	21.51¢
16	650	\$127.01	\$139.05	\$12.05	9.49%	21.39¢
17	700	\$136.06	\$149.03	\$12.97	9.54%	21.29¢
18	750	\$145.10	\$159.00	\$13.90	9.58%	21.20¢
19	800	\$154.15	\$168.98	\$14.83	9.62%	21.12¢
20	850	\$163.20	\$178.95	\$15.75	9.65%	21.05¢
21	900	\$172.25	\$188.93	\$16.68	9.68%	20.99¢
22	950	\$181.30	\$198.90	\$17.61	9.71%	20.94¢
23	1,000	\$190.34	\$208.88	\$18.53	9.74%	20.89¢
24	1,100	\$208.44	\$228.83	\$20.39	9.78%	20.80¢
25	1,200	\$226.54	\$248.78	\$22.24	9.82%	20.73¢
26	1,300	\$244.63	\$268.73	\$24.09	9.85%	20.67¢
27	1,400	\$262.73	\$288.68	\$25.95	9.88%	20.62¢
28	1,500	\$280.83	\$308.63	\$27.80	9.90%	20.58¢
29	2,000	\$371.31	\$408.38	\$37.07	9.98%	20.42¢
30	2,750	\$507.03	\$558.00	\$50.97	10.05%	20.29¢
31	4,000	\$733.24	\$807.37	\$74.13	10.11%	20.18¢

Assumes ~16% of June-September usage is on peak (per rate design billing determinants)

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Standard TOU - D1.11
October thru May

Case No.: U-21534
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
Oct-May On Peak \$0.08518
Oct-May Off Peak \$0.07354

Capacity Charges:
Oct-May On Peak \$0.01438
Oct-May Off Peak \$0.01241

Power Supply Surcharges: \$0.00000
REPS \$0.00

Service Charge \$8.50
Distribution Charge: \$0.08137

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
Oct-May On Peak \$0.06875
Oct-May Off Peak \$0.05873

Capacity Charges:
Oct-May On Peak \$0.03755
Oct-May Off Peak \$0.03208

Power Supply Surcharges: \$0.00000
REPS \$0.00

Service Charge: \$8.50
Distribution Charge: \$0.09451

Delivery Surcharges: \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
				Amount	Percent	
1	100	\$26.73	\$28.55	\$1.82	6.83%	28.55¢
2	120	\$30.19	\$32.38	\$2.19	7.25%	26.99¢
3	140	\$33.66	\$36.22	\$2.55	7.59%	25.87¢
4	160	\$37.13	\$40.05	\$2.92	7.86%	25.03¢
5	180	\$40.60	\$43.89	\$3.28	8.09%	24.38¢
6	200	\$44.07	\$47.72	\$3.65	8.28%	23.86¢
7	240	\$51.01	\$55.39	\$4.38	8.58%	23.08¢
8	280	\$57.95	\$63.06	\$5.11	8.82%	22.52¢
9	300	\$61.42	\$66.89	\$5.47	8.91%	22.30¢
10	350	\$70.09	\$76.48	\$6.39	9.11%	21.85¢
11	400	\$78.76	\$86.06	\$7.30	9.26%	21.52¢
12	450	\$87.44	\$95.65	\$8.21	9.39%	21.25¢
13	500	\$96.11	\$105.23	\$9.12	9.49%	21.05¢
14	550	\$104.78	\$114.82	\$10.03	9.58%	20.88¢
15	600	\$113.45	\$124.40	\$10.95	9.65%	20.73¢
16	650	\$122.13	\$133.99	\$11.86	9.71%	20.61¢
17	700	\$130.80	\$143.57	\$12.77	9.76%	20.51¢
18	750	\$139.47	\$153.16	\$13.68	9.81%	20.42¢
19	800	\$148.15	\$162.74	\$14.59	9.85%	20.34¢
20	850	\$156.82	\$172.33	\$15.51	9.89%	20.27¢
21	900	\$165.49	\$181.91	\$16.42	9.92%	20.21¢
22	950	\$174.16	\$191.50	\$17.33	9.95%	20.16¢
23	1,000	\$182.84	\$201.08	\$18.24	9.98%	20.11¢
24	1,100	\$200.18	\$220.25	\$20.07	10.02%	20.02¢
25	1,200	\$217.53	\$239.42	\$21.89	10.06%	19.95¢
26	1,300	\$234.87	\$258.59	\$23.72	10.10%	19.89¢
27	1,400	\$252.22	\$277.76	\$25.54	10.13%	19.84¢
28	1,500	\$269.57	\$296.93	\$27.37	10.15%	19.80¢
29	2,000	\$356.29	\$392.78	\$36.49	10.24%	19.64¢
30	2,750	\$486.39	\$536.56	\$50.17	10.31%	19.51¢
31	4,000	\$703.21	\$776.18	\$72.97	10.38%	19.40¢

Assumes ~13% of Oct-May usage is on peak (per rate design billing determinants)

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Overnight Savers - D1.13
June Thru September

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
June-Sept On Peak \$0.13470
June-Sept Off Peak \$0.09031
June-Sept Super Off Peak \$0.05816

Capacity Charges:
June-Sept On Peak \$0.02274
June-Sept Off Peak \$0.01525
June-Sept Super Off Peak \$0.00982

Power Supply Surcharges: \$0.00000
REPS \$0.00000

Service Charge: \$8.50
Distribution Charge:
June-Sept On Peak \$0.16298
June-Sept Off Peak \$0.12224
June-Sept Super Off Peak \$0.04075

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
June-Sept On Peak \$0.10846
June-Sept Off Peak \$0.07298
June-Sept Super Off Peak \$0.04609

Capacity Charges:
June-Sept On Peak \$0.05925
June-Sept Off Peak \$0.03987
June-Sept Super Off Peak \$0.02518

Power Supply Surcharges: \$0.00000
REPS \$0.00

Service Charge: \$8.50
Distribution Charge:
June-Sept On Peak \$0.19036
June-Sept Off Peak \$0.14277
June-Sept Super Off Peak \$0.04759

Delivery Surcharges: \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	100	\$31.95	\$34.58	\$2.62	8.21%	34.58¢
2	120	\$36.47	\$39.62	\$3.15	8.63%	33.01¢
3	140	\$40.98	\$44.65	\$3.67	8.96%	31.90¢
4	160	\$45.50	\$49.69	\$4.20	9.22%	31.06¢
5	180	\$50.01	\$54.73	\$4.72	9.44%	30.41¢
6	200	\$54.53	\$59.77	\$5.24	9.62%	29.89¢
7	240	\$63.56	\$69.85	\$6.29	9.90%	29.10¢
8	280	\$72.59	\$79.93	\$7.34	10.12%	28.55¢
9	300	\$77.10	\$84.97	\$7.87	10.20%	28.32¢
10	350	\$88.39	\$97.57	\$9.18	10.38%	27.88¢
11	400	\$99.68	\$110.17	\$10.49	10.52%	27.54¢
12	450	\$110.96	\$122.76	\$11.80	10.64%	27.28¢
13	500	\$122.25	\$135.36	\$13.11	10.73%	27.07¢
14	550	\$133.54	\$147.96	\$14.42	10.80%	26.90¢
15	600	\$144.82	\$160.56	\$15.73	10.86%	26.76¢
16	650	\$156.11	\$173.16	\$17.05	10.92%	26.64¢
17	700	\$167.40	\$185.75	\$18.36	10.97%	26.54¢
18	750	\$178.68	\$198.35	\$19.67	11.01%	26.45¢
19	800	\$189.97	\$210.95	\$20.98	11.04%	26.37¢
20	850	\$201.26	\$223.55	\$22.29	11.08%	26.30¢
21	900	\$212.54	\$236.15	\$23.60	11.10%	26.24¢
22	950	\$223.83	\$248.74	\$24.91	11.13%	26.18¢
23	1,000	\$235.12	\$261.34	\$26.22	11.15%	26.13¢
24	1,100	\$257.69	\$286.54	\$28.85	11.19%	26.05¢
25	1,200	\$280.27	\$311.74	\$31.47	11.23%	25.98¢
26	1,300	\$302.84	\$336.93	\$34.09	11.26%	25.92¢
27	1,400	\$325.41	\$362.13	\$36.71	11.28%	25.87¢
28	1,500	\$347.99	\$387.32	\$39.34	11.30%	25.82¢
29	2,000	\$460.86	\$513.31	\$52.45	11.38%	25.67¢
30	2,750	\$630.16	\$702.28	\$72.12	11.44%	25.54¢
31	4,000	\$912.33	\$1,017.23	\$104.90	11.50%	25.43¢

Assumes June-Sept is 16% on peak, 66% off peak, and 18% super off peak (per rate design billing determinants)

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Overnight Savers - D1.13
October thru May

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
Oct-May On Peak \$0.07692
Oct-May Off Peak \$0.06967
Oct-May Super Off Peak \$0.05816

Capacity Charges:
Oct-May On Peak \$0.01298
Oct-May Off Peak \$0.01176
Oct-May Super Off Peak \$0.00982

Power Supply Surcharges: \$0.00000
REPS \$0.00

Service Charge \$8.50
Distribution Charge:
Oct-May On Peak \$0.08149
Oct-May Off Peak \$0.06112
Oct-May Super Off Peak \$0.04075

Delivery Surcharges: \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge
Oct-May On Peak \$0.06186
Oct-May Off Peak \$0.05552
Oct-May Super Off Peak \$0.04609

Capacity Charges:
Oct-May On Peak \$0.03379
Oct-May Off Peak \$0.03033
Oct-May Super Off Peak \$0.02518

Power Supply Surcharges: \$0.00000
REPS \$0.00

Service Charge \$8.50
Distribution Charge:
Oct-May On Peak \$0.09518
Oct-May Off Peak \$0.07139
Oct-May Super Off Peak \$0.04759

Delivery Surcharges: \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	100	\$23.70	\$25.13	\$1.43	6.03%	25.13¢
2	120	\$26.57	\$28.28	\$1.72	6.46%	23.57¢
3	140	\$29.43	\$31.44	\$2.00	6.80%	22.45¢
4	160	\$32.30	\$34.59	\$2.29	7.09%	21.62¢
5	180	\$35.16	\$37.74	\$2.57	7.32%	20.96¢
6	200	\$38.03	\$40.89	\$2.86	7.52%	20.44¢
7	240	\$43.76	\$47.19	\$3.43	7.85%	19.66¢
8	280	\$49.49	\$53.49	\$4.00	8.09%	19.10¢
9	300	\$52.35	\$56.64	\$4.29	8.20%	18.88¢
10	350	\$59.51	\$64.52	\$5.01	8.41%	18.43¢
11	400	\$66.67	\$72.40	\$5.72	8.58%	18.10¢
12	450	\$73.84	\$80.27	\$6.44	8.72%	17.84¢
13	500	\$81.00	\$88.15	\$7.15	8.83%	17.63¢
14	550	\$88.16	\$96.03	\$7.87	8.92%	17.46¢
15	600	\$95.32	\$103.90	\$8.58	9.00%	17.32¢
16	650	\$102.48	\$111.78	\$9.30	9.07%	17.20¢
17	700	\$109.64	\$119.66	\$10.01	9.13%	17.09¢
18	750	\$116.81	\$127.53	\$10.73	9.18%	17.00¢
19	800	\$123.97	\$135.41	\$11.44	9.23%	16.93¢
20	850	\$131.13	\$143.29	\$12.16	9.27%	16.86¢
21	900	\$138.29	\$151.16	\$12.87	9.31%	16.80¢
22	950	\$145.45	\$159.04	\$13.59	9.34%	16.74¢
23	1,000	\$152.61	\$166.92	\$14.30	9.37%	16.69¢
24	1,100	\$166.94	\$182.67	\$15.73	9.42%	16.61¢
25	1,200	\$181.26	\$198.43	\$17.16	9.47%	16.54¢
26	1,300	\$195.59	\$214.18	\$18.59	9.51%	16.48¢
27	1,400	\$209.91	\$229.93	\$20.02	9.54%	16.42¢
28	1,500	\$224.23	\$245.69	\$21.45	9.57%	16.38¢
29	2,000	\$295.85	\$324.46	\$28.61	9.67%	16.22¢
30	2,750	\$403.28	\$442.61	\$39.33	9.75%	16.09¢
31	4,000	\$582.32	\$639.53	\$57.21	9.82%	15.99¢

Assumes Oct-May is 13% on peak, 65% off peak, and 22% super off peak (per rate design billing determinants)

**Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Space Heating - D2
June thru October**

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge: \$0.06274

Capacity Charges:

First 17 KWH/Day \$0.01059

Excess \$0.01514

Power Supply Surcharges \$0.00000

REPS \$0.00

Service Charge \$8.50

Distribution Charge \$0.08137

Delivery Surcharges \$0.004375

LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge: \$0.05498

Capacity Charges:

First 17 KWH/Day \$0.02817

Excess \$0.04027

Power Supply Surcharges \$0.00000

REPS \$0.00

Service Charge \$8.50

Distribution Charge \$0.09451

Delivery Surcharges \$0.004375

LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	100	\$25.29	\$27.58	\$2.30	9.08%	27.58¢
2	120	\$28.47	\$31.22	\$2.76	9.68%	26.02¢
3	160	\$34.83	\$38.51	\$3.67	10.55%	24.07¢
4	180	\$38.01	\$42.15	\$4.13	10.87%	23.41¢
5	200	\$41.20	\$45.79	\$4.59	11.15%	22.89¢
6	240	\$47.56	\$53.07	\$5.51	11.59%	22.11¢
7	280	\$53.92	\$60.35	\$6.43	11.92%	21.55¢
8	300	\$57.10	\$63.99	\$6.89	12.06%	21.33¢
9	350	\$65.06	\$73.09	\$8.04	12.35%	20.88¢
10	400	\$73.01	\$82.19	\$9.18	12.58%	20.55¢
11	450	\$80.96	\$91.30	\$10.33	12.76%	20.29¢
12	500	\$88.92	\$100.40	\$11.48	12.91%	20.08¢
13	550	\$97.05	\$109.98	\$12.93	13.32%	20.00¢
14	600	\$105.23	\$119.69	\$14.46	13.74%	19.95¢
15	650	\$113.42	\$129.40	\$15.98	14.09%	19.91¢
16	700	\$121.60	\$139.10	\$17.51	14.40%	19.87¢
17	750	\$129.78	\$148.81	\$19.03	14.67%	19.84¢
18	800	\$137.96	\$158.52	\$20.56	14.90%	19.81¢
19	850	\$146.14	\$168.22	\$22.08	15.11%	19.79¢
20	900	\$154.32	\$177.93	\$23.61	15.30%	19.77¢
21	950	\$162.50	\$187.64	\$25.13	15.47%	19.75¢
22	1,000	\$170.68	\$197.34	\$26.66	15.62%	19.73¢
23	1,100	\$187.05	\$216.76	\$29.71	15.88%	19.71¢
24	1,200	\$203.41	\$236.17	\$32.76	16.11%	19.68¢
25	1,300	\$219.77	\$255.58	\$35.81	16.30%	19.66¢
26	1,400	\$236.13	\$275.00	\$38.86	16.46%	19.64¢
27	1,500	\$252.50	\$294.41	\$41.91	16.60%	19.63¢
28	2,000	\$334.31	\$391.48	\$57.17	17.10%	19.57¢
29	3,000	\$497.93	\$585.61	\$87.68	17.61%	19.52¢
30	4,000	\$661.56	\$779.75	\$118.19	17.87%	19.49¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Residential Service Rate Space Heating - D2
November thru May

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge: \$0.06274

Capacity Charges:

First 20 KWH/Day \$0.00624

Second Block: \$0.00244

Power Supply Surcharges \$0.00000
REPS \$0.00

Service Charge \$8.50

Distribution Charge \$0.08137

Delivery Surcharges \$0.004375
LIEAF \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Non-Capacity Charge: \$0.05498

Capacity Charges:

First 20 KWH/Day \$0.01660

Excess \$0.00649

Power Supply Surcharges \$0.00000
REPS \$0.00

Service Charge \$8.50

Distribution Charge \$0.09451

Delivery Surcharges \$0.004375
LIEAF \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
				Amount	Percent	
1	100	\$24.85	\$26.43	\$1.57	6.33%	26.43¢
2	120	\$27.95	\$29.84	\$1.89	6.76%	24.86¢
3	160	\$34.14	\$36.65	\$2.52	7.38%	22.91¢
4	180	\$37.23	\$40.06	\$2.83	7.61%	22.26¢
5	200	\$40.33	\$43.47	\$3.15	7.81%	21.74¢
6	240	\$46.51	\$50.29	\$3.78	8.12%	20.95¢
7	280	\$52.70	\$57.11	\$4.41	8.36%	20.40¢
8	300	\$55.80	\$60.52	\$4.72	8.46%	20.17¢
9	350	\$63.53	\$69.04	\$5.51	8.67%	19.73¢
10	400	\$71.27	\$77.57	\$6.30	8.83%	19.39¢
11	450	\$79.01	\$86.09	\$7.08	8.97%	19.13¢
12	500	\$86.74	\$94.61	\$7.87	9.07%	18.92¢
13	550	\$94.48	\$103.14	\$8.66	9.16%	18.75¢
14	600	\$102.22	\$111.66	\$9.44	9.24%	18.61¢
15	650	\$109.76	\$119.68	\$9.92	9.03%	18.41¢
16	700	\$117.31	\$127.69	\$10.39	8.85%	18.24¢
17	750	\$124.85	\$135.71	\$10.86	8.70%	18.09¢
18	800	\$132.40	\$143.73	\$11.33	8.56%	17.97¢
19	850	\$139.95	\$151.75	\$11.80	8.43%	17.85¢
20	900	\$147.49	\$159.77	\$12.27	8.32%	17.75¢
21	950	\$155.04	\$167.78	\$12.74	8.22%	17.66¢
22	1,000	\$162.59	\$175.80	\$13.22	8.13%	17.58¢
23	1,100	\$177.68	\$191.84	\$14.16	7.97%	17.44¢
24	1,200	\$192.77	\$207.87	\$15.10	7.83%	17.32¢
25	1,300	\$207.86	\$223.91	\$16.05	7.72%	17.22¢
26	1,400	\$222.96	\$239.94	\$16.99	7.62%	17.14¢
27	1,500	\$238.05	\$255.98	\$17.93	7.53%	17.07¢
28	2,000	\$313.51	\$336.16	\$22.65	7.22%	16.81¢
29	3,000	\$464.44	\$496.51	\$32.08	6.91%	16.55¢
30	4,000	\$615.36	\$656.87	\$41.51	6.74%	16.42¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Water Heating Service Rate - D5 Residential

Case No.: U-21534

Exhibit: A-16

Schedule: F4

Witness: A. Willis

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Present Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge **\$0.04132**

Capacity Charge **\$0.00698**

Power Supply Surcharges **\$0.00000**

Distribution Charges
Service Charge **\$1.95**

Distribution Energy \$0.08137

Delivery Surcharges \$0.004375

Proposed Rates and Current Surcharges:

Power Supply Charges

Non-Capacity Charge **\$0.03303**

Capacity Charge **\$0.01805**

Power Supply Surcharges **\$0.00000**

Distribution Charges
Service Charge **\$1.95**

Distribution Energy \$0.09451

Delivery Surcharges \$0.004375

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) (e) Increase Amount Percent		(f) Proposed Unit Cost
1	100	\$15.35	\$16.95	\$1.59	10.37%	16.95¢
2	200	\$28.76	\$31.94	\$3.18	11.07%	15.97¢
3	300	\$42.16	\$46.94	\$4.78	11.33%	15.65¢
4	400	\$55.57	\$61.94	\$6.37	11.46%	15.48¢
5	500	\$68.97	\$76.93	\$7.96	11.54%	15.39¢
6	600	\$82.38	\$91.93	\$9.55	11.60%	15.32¢
7	700	\$95.78	\$106.93	\$11.14	11.63%	15.28¢
8	800	\$109.19	\$121.92	\$12.74	11.66%	15.24¢
9	900	\$122.59	\$136.92	\$14.33	11.69%	15.21¢
10	1,000	\$136.00	\$151.92	\$15.92	11.71%	15.19¢
10	1,100	\$149.40	\$166.91	\$17.51	11.72%	15.17¢
10	1,200	\$162.80	\$181.91	\$19.10	11.73%	15.16¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
General Service Rate - D3

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy Charge **\$0.01010**
Non-capacity energy charge **\$0.07096**

Power Supply Surcharges: **\$0.000000**

Distribution Charges:

Service Charge **\$11.25**

Distribution Energy **\$0.05288**

Distribution Surcharges: **\$0.001477**

Energy Waste Reduction **\$5.50**

LIEAF Factor **\$0.88**

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy Charge **\$0.02605**
Non-capacity energy charge **\$0.05870**

Power Supply Surcharges: **\$0.000000**

Distribution Charges:

Service Charge **\$11.25**

Distribution Energy **\$0.06156**

Distribution Surcharges: **\$0.001477**

Energy Waste Reduction **\$5.50**

LIEAF Factor **\$0.88**

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	400	\$71.80	\$76.74	\$4.95	6.89%	19.19¢
2	600	\$98.88	\$106.30	\$7.42	7.51%	17.72¢
3	800	\$125.96	\$135.86	\$9.90	7.86%	16.98¢
4	1,000	\$153.05	\$165.42	\$12.37	8.08%	16.54¢
5	1,200	\$180.13	\$194.97	\$14.84	8.24%	16.25¢
6	1,400	\$207.21	\$224.53	\$17.32	8.36%	16.04¢
7	1,600	\$234.30	\$254.09	\$19.79	8.45%	15.88¢
8	1,800	\$261.38	\$283.65	\$22.27	8.52%	15.76¢
9	2,000	\$288.46	\$313.20	\$24.74	8.58%	15.66¢
10	2,200	\$315.55	\$342.76	\$27.21	8.62%	15.58¢
11	2,400	\$342.63	\$372.32	\$29.69	8.66%	15.51¢
12	2,500	\$356.17	\$387.10	\$30.93	8.68%	15.48¢
13	3,000	\$423.88	\$460.99	\$37.11	8.75%	15.37¢
14	3,500	\$491.59	\$534.88	\$43.30	8.81%	15.28¢
15	4,000	\$559.30	\$608.78	\$49.48	8.85%	15.22¢
16	4,500	\$627.01	\$682.67	\$55.67	8.88%	15.17¢
17	5,000	\$694.72	\$756.57	\$61.85	8.90%	15.13¢
18	5,500	\$762.42	\$830.46	\$68.03	8.92%	15.10¢
19	6,000	\$830.13	\$904.35	\$74.22	8.94%	15.07¢
20	6,500	\$897.84	\$978.25	\$80.41	8.96%	15.05¢
21	7,000	\$965.55	\$1,052.14	\$86.59	8.97%	15.03¢
22	7,500	\$1,033.26	\$1,126.03	\$92.77	8.98%	15.01¢
23	8,000	\$1,100.97	\$1,199.93	\$98.96	8.99%	15.00¢
24	8,500	\$1,168.67	\$1,273.82	\$105.15	9.00%	14.99¢
25	9,000	\$1,236.38	\$1,347.71	\$111.33	9.00%	14.97¢
26	9,500	\$1,304.09	\$1,421.61	\$117.52	9.01%	14.96¢
27	10,000	\$1,371.80	\$1,495.50	\$123.70	9.02%	14.96¢
28	12,000	\$1,642.63	\$1,791.07	\$148.44	9.04%	14.93¢
29	15,000	\$2,048.89	\$2,234.44	\$185.55	9.06%	14.90¢
30	18,000	\$2,455.14	\$2,677.80	\$222.66	9.07%	14.88¢
31	21,000	\$2,861.39	\$3,121.16	\$259.77	9.08%	14.86¢
32	24,000	\$3,267.64	\$3,564.52	\$296.88	9.09%	14.85¢
33	27,000	\$3,673.89	\$4,007.88	\$333.99	9.09%	14.84¢
34	30,000	\$4,080.14	\$4,451.24	\$371.10	9.10%	14.84¢
35	35,000	\$4,757.23	\$5,190.18	\$432.95	9.10%	14.83¢
36	40,000	\$5,434.31	\$5,929.11	\$494.80	9.11%	14.82¢
37	45,000	\$6,111.40	\$6,668.05	\$556.65	9.11%	14.82¢
38	50,000	\$6,788.48	\$7,406.98	\$618.50	9.11%	14.81¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Secondary Educational Institute Rate - D3.2

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy Charge \$0.00939
Non-capacity energy \$0.06937

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge \$11.25

Distribution Energy \$0.05288

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy Charge \$0.02426
Non-capacity energy \$0.05764

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge \$11.25

Distribution Energy \$0.06156

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	400	\$70.88	\$75.60	\$4.73	6.67%	18.90¢
2	600	\$97.50	\$104.59	\$7.09	7.27%	17.43¢
3	800	\$124.12	\$133.58	\$9.46	7.62%	16.70¢
4	1,000	\$150.75	\$162.57	\$11.82	7.84%	16.26¢
5	1,200	\$177.37	\$191.55	\$14.18	8.00%	15.96¢
6	1,400	\$203.99	\$220.54	\$16.55	8.11%	15.75¢
7	1,600	\$230.62	\$249.53	\$18.91	8.20%	15.60¢
8	1,800	\$257.24	\$278.52	\$21.28	8.27%	15.47¢
9	2,000	\$283.86	\$307.50	\$23.64	8.33%	15.38¢
10	2,200	\$310.49	\$336.49	\$26.00	8.38%	15.30¢
11	2,400	\$337.11	\$365.48	\$28.37	8.42%	15.23¢
12	2,500	\$350.42	\$379.97	\$29.55	8.43%	15.20¢
13	3,000	\$416.98	\$452.44	\$35.46	8.50%	15.08¢
14	3,500	\$483.54	\$524.91	\$41.37	8.56%	15.00¢
15	4,000	\$550.10	\$597.38	\$47.28	8.59%	14.93¢
16	4,500	\$616.66	\$669.85	\$53.19	8.63%	14.89¢
17	5,000	\$683.22	\$742.32	\$59.10	8.65%	14.85¢
18	5,500	\$749.77	\$814.78	\$65.01	8.67%	14.81¢
19	6,000	\$816.33	\$887.25	\$70.92	8.69%	14.79¢
20	6,500	\$882.89	\$959.72	\$76.83	8.70%	14.76¢
21	7,000	\$949.45	\$1,032.19	\$82.74	8.71%	14.75¢
22	7,500	\$1,016.01	\$1,104.66	\$88.65	8.73%	14.73¢
23	8,000	\$1,082.57	\$1,177.13	\$94.56	8.73%	14.71¢
24	8,500	\$1,149.12	\$1,249.59	\$100.47	8.74%	14.70¢
25	9,000	\$1,215.68	\$1,322.06	\$106.38	8.75%	14.69¢
26	9,500	\$1,282.24	\$1,394.53	\$112.29	8.76%	14.68¢
27	10,000	\$1,348.80	\$1,467.00	\$118.20	8.76%	14.67¢
28	12,000	\$1,615.03	\$1,756.87	\$141.84	8.78%	14.64¢
29	15,000	\$2,014.39	\$2,191.69	\$177.30	8.80%	14.61¢
30	18,000	\$2,413.74	\$2,626.50	\$212.76	8.81%	14.59¢
31	21,000	\$2,813.09	\$3,061.31	\$248.22	8.82%	14.58¢
32	24,000	\$3,212.44	\$3,496.12	\$283.68	8.83%	14.57¢
33	27,000	\$3,611.79	\$3,930.93	\$319.14	8.84%	14.56¢
34	30,000	\$4,011.14	\$4,365.74	\$354.60	8.84%	14.55¢
35	35,000	\$4,676.73	\$5,090.43	\$413.70	8.85%	14.54¢
36	40,000	\$5,342.31	\$5,815.11	\$472.80	8.85%	14.54¢
37	45,000	\$6,007.90	\$6,539.80	\$531.90	8.85%	14.53¢
38	50,000	\$6,673.48	\$7,264.48	\$591.00	8.86%	14.53¢

**Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible General Service Rate - D3.3**

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy Charge **\$0.00844**
Non-capacity energy **\$0.05929**

Power Supply Surcharges: **\$0.000000**

Distribution Charges:

Service Charge **\$11.25**

Distribution Energy \$0.05288

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy Charge **\$0.02176**
Non-capacity energy **\$0.04905**

Power Supply Surcharges: **\$0.000000**

Distribution Charges:

Service Charge **\$11.25**

Distribution Energy \$0.06156

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	400	\$66.46	\$71.17	\$4.70	7.08%	17.79¢
2	600	\$90.88	\$97.94	\$7.06	7.76%	16.32¢
3	800	\$115.30	\$124.71	\$9.41	8.16%	15.59¢
4	1,000	\$139.72	\$151.48	\$11.76	8.42%	15.15¢
5	1,200	\$164.13	\$178.25	\$14.11	8.60%	14.85¢
6	1,400	\$188.55	\$205.02	\$16.46	8.73%	14.64¢
7	1,600	\$212.97	\$231.79	\$18.82	8.84%	14.49¢
8	1,800	\$237.39	\$258.55	\$21.17	8.92%	14.36¢
9	2,000	\$261.80	\$285.32	\$23.52	8.98%	14.27¢
10	2,200	\$286.22	\$312.09	\$25.87	9.04%	14.19¢
11	2,400	\$310.64	\$338.86	\$28.22	9.09%	14.12¢
12	2,500	\$322.85	\$352.25	\$29.40	9.11%	14.09¢
13	3,000	\$383.89	\$419.17	\$35.28	9.19%	13.97¢
14	3,500	\$444.93	\$486.09	\$41.16	9.25%	13.89¢
15	4,000	\$505.98	\$553.02	\$47.04	9.30%	13.83¢
16	4,500	\$567.02	\$619.94	\$52.92	9.33%	13.78¢
17	5,000	\$628.07	\$686.87	\$58.80	9.36%	13.74¢
18	5,500	\$689.11	\$753.79	\$64.68	9.39%	13.71¢
19	6,000	\$750.15	\$820.71	\$70.56	9.41%	13.68¢
20	6,500	\$811.20	\$887.64	\$76.44	9.42%	13.66¢
21	7,000	\$872.24	\$954.56	\$82.32	9.44%	13.64¢
22	7,500	\$933.28	\$1,021.48	\$88.20	9.45%	13.62¢
23	8,000	\$994.33	\$1,088.41	\$94.08	9.46%	13.61¢
24	8,500	\$1,055.37	\$1,155.33	\$99.96	9.47%	13.59¢
25	9,000	\$1,116.41	\$1,222.25	\$105.84	9.48%	13.58¢
26	9,500	\$1,177.46	\$1,289.18	\$111.72	9.49%	13.57¢
27	10,000	\$1,238.50	\$1,356.10	\$117.60	9.50%	13.56¢
28	12,000	\$1,482.67	\$1,623.79	\$141.12	9.52%	13.53¢
29	15,000	\$1,848.94	\$2,025.34	\$176.40	9.54%	13.50¢
30	18,000	\$2,215.20	\$2,426.88	\$211.68	9.56%	13.48¢
31	21,000	\$2,581.46	\$2,828.42	\$246.96	9.57%	13.47¢
32	24,000	\$2,947.72	\$3,229.96	\$282.24	9.57%	13.46¢
33	27,000	\$3,313.98	\$3,631.50	\$317.52	9.58%	13.45¢
34	30,000	\$3,680.24	\$4,033.04	\$352.80	9.59%	13.44¢
35	33,000	\$4,046.50	\$4,434.58	\$388.08	9.59%	13.44¢
36	36,000	\$4,412.76	\$4,836.12	\$423.36	9.59%	13.43¢
37	39,000	\$4,779.02	\$5,237.66	\$458.64	9.60%	13.43¢
38	42,000	\$5,145.28	\$5,639.20	\$493.92	9.60%	13.43¢
39	45,000	\$5,511.55	\$6,040.75	\$529.20	9.60%	13.42¢
40	50,000	\$6,121.98	\$6,709.98	\$588.00	9.60%	13.42¢

<u>Present Rates and Current Surcharges:</u>				<u>Proposed Rates and Current Surcharges:</u>			
Power Supply Charges:				Power Supply Charges:			
Capacity Charge:				Capacity Charges:			
Demand Charge			\$3.57	Demand Charge			\$9.18
Non-capacity Charges:				Non-capacity Charges:			
Demand Charge			\$13.02	Demand Charge			\$8.07
Energy Charges:				Energy Charges:			
First 200kWh/kW			\$0.04012	First 200kWh/kW			\$0.04169
Over 200kWh/kW			\$0.03097	Over 200kWh/kW			\$0.03219
Power Supply Surcharges:			\$0.000000	Power Supply Surcharges:			\$0.000000
Distribution Charges:				Distribution Charges:			
Service Charge:			\$13.67	Service Charge:			\$13.67
Demand Charge:			\$21.80	Demand Charge:			\$25.21
Distribution Energy:			\$0.00000	Distribution Energy:			\$0.00000
Distribution Surcharges:			\$0.000882	Distribution Surcharges:			\$0.000882
Energy Waste Reduction			\$140.21	Energy Waste Reduction			\$140.21
LIEAF Factor			\$0.88	LIEAF Factor			\$0.88
IRM			\$0.2454	IRM			\$0.2454

Line No.	(a) Monthly kWh Use	(b) On-Peak Use	(c) Present Net Monthly Bill	(d) Proposed Net Monthly Bill	(e) Increase		(f)	(g) Proposed Unit Cost
					Amount	Percent		
1	5	300	\$404.87	\$427.40	\$22.53	5.56%		28.49¢
2	5	400	\$420.79	\$443.93	\$23.14	5.50%		22.20¢
3	5	500	\$436.72	\$460.47	\$23.75	5.44%		18.42¢
4								
5	10	300	\$654.97	\$700.03	\$45.06	6.88%		23.33¢
6	10	400	\$686.82	\$733.10	\$46.28	6.74%		18.33¢
7	10	500	\$718.67	\$766.17	\$47.50	6.61%		15.32¢
8								
9	25	300	\$1,405.29	\$1,517.94	\$112.65	8.02%		20.24¢
10	25	400	\$1,484.92	\$1,600.62	\$115.70	7.79%		16.01¢
11	25	500	\$1,564.55	\$1,683.30	\$118.75	7.59%		13.47¢
12								
13	50	300	\$2,655.81	\$2,881.11	\$225.30	8.48%		19.21¢
14	50	400	\$2,815.07	\$3,046.47	\$231.40	8.22%		15.23¢
15	50	500	\$2,974.33	\$3,211.83	\$237.50	7.98%		12.85¢
16								
17	75	300	\$3,906.34	\$4,244.29	\$337.95	8.65%		18.86¢
18	75	400	\$4,145.23	\$4,492.33	\$347.10	8.37%		14.97¢
19	75	500	\$4,384.12	\$4,740.37	\$356.25	8.13%		12.64¢
20								
21	100	300	\$5,156.86	\$5,607.46	\$450.60	8.74%		18.69¢
22	100	400	\$5,475.38	\$5,938.18	\$462.80	8.45%		14.85¢
23	100	500	\$5,793.90	\$6,268.90	\$475.00	8.20%		12.54¢
24								
25	200	300	\$10,158.96	\$11,060.16	\$901.20	8.87%		18.43¢
26	200	400	\$10,796.00	\$11,721.60	\$925.60	8.57%		14.65¢
27	200	500	\$11,433.04	\$12,383.04	\$950.00	8.31%		12.38¢
28								
29	300	300	\$15,161.06	\$16,512.86	\$1,351.80	8.92%		18.35¢
30	300	400	\$16,116.62	\$17,505.02	\$1,388.40	8.61%		14.59¢
31	300	500	\$17,072.18	\$18,497.18	\$1,425.00	8.35%		12.33¢
32								
33	400	300	\$20,163.16	\$21,965.56	\$1,802.40	8.94%		18.30¢
34	400	400	\$21,437.24	\$23,288.44	\$1,851.20	8.64%		14.56¢
35	400	500	\$22,711.32	\$24,611.32	\$1,900.00	8.37%		12.31¢
36								
37	500	300	\$25,165.26	\$27,418.26	\$2,253.00	8.95%		18.28¢
38	500	400	\$26,757.86	\$29,071.86	\$2,314.00	8.65%		14.54¢
39	500	500	\$28,350.46	\$30,725.46	\$2,375.00	8.38%		12.29¢
40								
41	750	300	\$37,670.51	\$41,050.01	\$3,379.50	8.97%		18.24¢
42	750	400	\$40,059.41	\$43,530.41	\$3,471.00	8.66%		14.51¢
43	750	500	\$42,448.31	\$46,010.81	\$3,562.50	8.39%		12.27¢
44								
45	1000	300	\$50,175.76	\$54,681.76	\$4,506.00	8.98%		18.23¢
46	1000	400	\$53,360.96	\$57,988.96	\$4,628.00	8.67%		14.50¢
47	1000	500	\$56,546.16	\$61,296.16	\$4,750.00	8.40%		12.26¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Water Heating Service Rate - D5 Commercial

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy \$0.00595
Non-capacity Energy \$0.04178

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge \$1.95

Distribution Energy \$0.05288

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity Energy \$0.01534
Non-capacity Energy \$0.03457

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge \$1.95

Distribution Energy \$0.06156

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase		(f) Proposed Unit Cost
				Amount	Percent	
1	100	\$18.54	\$19.62	\$1.09	5.86%	19.62¢
2	200	\$28.75	\$30.92	\$2.17	7.56%	15.46¢
3	300	\$38.96	\$42.21	\$3.26	8.36%	14.07¢
4	400	\$49.16	\$53.51	\$4.34	8.84%	13.38¢
5	500	\$59.37	\$64.80	\$5.43	9.15%	12.96¢
6	600	\$69.58	\$76.10	\$6.52	9.36%	12.68¢
7	700	\$79.79	\$87.39	\$7.60	9.53%	12.48¢
8	800	\$90.00	\$98.69	\$8.69	9.65%	12.34¢
9	900	\$100.21	\$109.98	\$9.77	9.75%	12.22¢
10	1,000	\$110.42	\$121.28	\$10.86	9.84%	12.13¢
11	1,100	\$120.63	\$132.57	\$11.95	9.90%	12.05¢
12	1,200	\$130.83	\$143.87	\$13.03	9.96%	11.99¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Greenhouse Lighting Service Rate - Standard Contract Rider No. R7

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 28 of 53

Present Rates and Current Surcharges:

Power Supply Charges:

Capacity energy \$0.00577
Non-capacity energy \$0.04054

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge: \$1.95

Distribution Energy \$0.05288

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity energy \$0.01488
Non-capacity energy \$0.03354

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge: \$1.95

Distribution Energy \$0.06156

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	400	\$48.60	\$52.91	\$4.32	8.88%	13.23¢
2	600	\$68.73	\$75.20	\$6.47	9.42%	12.53¢
3	800	\$88.86	\$97.50	\$8.63	9.71%	12.19¢
4	1,000	\$109.00	\$119.79	\$10.79	9.90%	11.98¢
5	1,200	\$129.13	\$142.08	\$12.95	10.03%	11.84¢
6	1,400	\$149.26	\$164.37	\$15.11	10.12%	11.74¢
7	1,600	\$169.40	\$186.66	\$17.26	10.19%	11.67¢
8	1,800	\$189.53	\$208.95	\$19.42	10.25%	11.61¢
9	2,000	\$209.66	\$231.24	\$21.58	10.29%	11.56¢
10	2,500	\$260.00	\$286.97	\$26.98	10.38%	11.48¢
11	3,000	\$310.33	\$342.70	\$32.37	10.43%	11.42¢
12	4,000	\$411.00	\$454.16	\$43.16	10.50%	11.35¢
13	5,000	\$511.67	\$565.62	\$53.95	10.54%	11.31¢
14	6,000	\$612.33	\$677.07	\$64.74	10.57%	11.28¢
15	7,000	\$713.00	\$788.53	\$75.53	10.59%	11.26¢
16	8,000	\$813.67	\$899.99	\$86.32	10.61%	11.25¢
17	9,000	\$914.33	\$1,011.44	\$97.11	10.62%	11.24¢
18	10,000	\$1,015.00	\$1,122.90	\$107.90	10.63%	11.23¢
19	12,000	\$1,216.33	\$1,345.81	\$129.48	10.65%	11.22¢
20	15,000	\$1,518.34	\$1,680.19	\$161.85	10.66%	11.20¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Commercial Space Conditioning Rate - Standard Contract Rider No. R8
June Thru October

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 29 of 53

Present Rates and Current Surcharges:

Power Supply Charges:

Capacity energy \$0.01539
Non-capacity energy \$0.06173

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge: \$11.25

Distribution Energy \$0.05288

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity energy \$0.04013
Non-capacity energy \$0.05099

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge: \$11.25

Distribution Energy \$0.06156

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line	Monthly	Present Net	Proposed Net	Increase		Proposed
No.	kWh Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	1,000	\$149.11	\$171.79	\$22.68	15.21%	17.18¢
2	3,000	\$412.06	\$480.10	\$68.04	16.51%	16.00¢
3	5,000	\$675.02	\$788.42	\$113.40	16.80%	15.77¢
4	7,000	\$937.97	\$1,096.73	\$158.76	16.93%	15.67¢
5	8,000	\$1,069.45	\$1,250.89	\$181.44	16.97%	15.64¢
6	9,000	\$1,200.92	\$1,405.04	\$204.12	17.00%	15.61¢
7	10,000	\$1,332.40	\$1,559.20	\$226.80	17.02%	15.59¢
8	12,000	\$1,595.35	\$1,867.51	\$272.16	17.06%	15.56¢
9	13,000	\$1,726.83	\$2,021.67	\$294.84	17.07%	15.55¢
10	15,000	\$1,989.79	\$2,329.99	\$340.20	17.10%	15.53¢
11	17,000	\$2,252.74	\$2,638.30	\$385.56	17.12%	15.52¢
12	20,000	\$2,647.17	\$3,100.77	\$453.60	17.14%	15.50¢
13	28,000	\$3,698.99	\$4,334.03	\$635.04	17.17%	15.48¢
14	30,000	\$3,961.94	\$4,642.34	\$680.40	17.17%	15.47¢
15	35,000	\$4,619.33	\$5,413.13	\$793.80	17.18%	15.47¢
16	40,000	\$5,276.71	\$6,183.91	\$907.20	17.19%	15.46¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Commercial Space Heating - Standard Contract Rider No. R8
November Thru May

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 30 of 53

Present Rates and Current Surcharges:

Power Supply Charges:

Capacity energy
1st 1,000 kWh \$0.01539
Excess \$0.00510
Non-capacity energy \$0.06173

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge: \$11.25

Distribution Energy \$0.05288

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

Proposed Rates and Current Surcharges:

Power Supply Charges:

Capacity energy
1st 1,000 kWh \$0.04013
Excess \$0.01330
Non-capacity energy \$0.05099

Power Supply Surcharges: \$0.000000

Distribution Charges:

Service Charge: \$11.25

Distribution Energy \$0.06156

Distribution Surcharges: \$0.001477
Energy Waste Reduction \$5.50
LIEAF Factor \$0.88

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
				Amount	Percent	
1	1,000	149.107	\$171.79	\$22.68	15.21%	17.18¢
2	3,000	\$391.48	\$426.44	\$34.96	8.93%	14.21¢
3	5,000	\$633.86	\$681.10	\$47.24	7.45%	13.62¢
4	7,000	\$876.23	\$935.75	\$59.52	6.79%	13.37¢
5	8,000	\$997.42	\$1,063.08	\$65.66	6.58%	13.29¢
6	9,000	\$1,118.60	\$1,190.40	\$71.80	6.42%	13.23¢
7	10,000	\$1,239.79	\$1,317.73	\$77.94	6.29%	13.18¢
8	12,000	\$1,482.16	\$1,572.38	\$90.22	6.09%	13.10¢
9	13,000	\$1,603.35	\$1,699.71	\$96.36	6.01%	13.07¢
10	15,000	\$1,845.73	\$1,954.37	\$108.64	5.89%	13.03¢
11	17,000	\$2,088.10	\$2,209.02	\$120.92	5.79%	12.99¢
12	20,000	\$2,451.66	\$2,591.00	\$139.34	5.68%	12.96¢
13	28,000	\$3,421.16	\$3,609.62	\$188.46	5.51%	12.89¢
14	30,000	\$3,663.53	\$3,864.27	\$200.74	5.48%	12.88¢
15	35,000	\$4,269.47	\$4,500.91	\$231.44	5.42%	12.86¢
16	40,000	\$4,875.40	\$5,137.54	\$262.14	5.38%	12.84¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Primary Supply Rate - D11
Primary Less Than 24kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 31 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$3.56
Voltage Level Discount \$0.00

Non-Capacity:

Power Supply Demand \$13.33
Voltage Level Discount \$0.00

Energy

On-Peak Rate \$0.04257
Off-Peak Rate \$0.03257
Voltage Discount

Surcharges:

PSCR \$0.00000
REPS >41,500kWh/ \$0.00
11,501-41,50 \$0.00

Distribution

Service Charge: \$70
Distribution Charges:
Demand \$6.15
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0727

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$9.19
Voltage Level Adjustment \$0.00

Non-Capacity:

Power Supply Demand \$8.35
Voltage Level Discount \$0.00

Energy

On-Peak Rate \$0.04388
Off-Peak Rate \$0.03388
Voltage Discount

Surcharges:

PSCR \$0.00000
REPS \$0.00
\$0.00

Distribution

Service Charge: \$70
Distribution Charges:
Demand \$6.66
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0727

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line	Monthly	Hours			Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use		Percent	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	50	300	@	30%	\$3,010	\$3,088	\$78	2.58%	20.59¢
2	50	400	@	30%	\$3,193	\$3,277	\$84	2.64%	16.38¢
3	50	500	@	25%	\$3,362	\$3,453	\$91	2.70%	13.81¢
4	50	600	@	25%	\$3,542	\$3,639	\$97	2.75%	12.13¢
5	50	650	@	25%	\$3,632	\$3,733	\$101	2.77%	11.49¢
6									
7	100	300	@	30%	\$4,713	\$4,868	\$155	3.30%	16.23¢
8	100	400	@	30%	\$5,077	\$5,246	\$168	3.32%	13.11¢
9	100	500	@	25%	\$5,417	\$5,598	\$182	3.35%	11.20¢
10	100	600	@	25%	\$5,776	\$5,971	\$195	3.37%	9.95¢
11	100	650	@	25%	\$5,956	\$6,157	\$201	3.38%	9.47¢
12									
13	500	300	@	30%	\$18,332	\$19,109	\$777	4.24%	12.74¢
14	500	400	@	30%	\$20,155	\$20,997	\$842	4.18%	10.50¢
15	500	500	@	25%	\$21,852	\$22,760	\$908	4.15%	9.10¢
16	500	600	@	25%	\$23,650	\$24,623	\$973	4.11%	8.21¢
17	500	650	@	25%	\$24,549	\$25,554	\$1,006	4.10%	7.86¢
18									
19	1,000	300	@	30%	\$35,356	\$36,909	\$1,553	4.39%	12.30¢
20	1,000	400	@	30%	\$39,001	\$40,685	\$1,684	4.32%	10.17¢
21	1,000	500	@	25%	\$42,397	\$44,212	\$1,815	4.28%	8.84¢
22	1,000	600	@	25%	\$45,992	\$47,938	\$1,946	4.23%	7.99¢
23	1,000	650	@	25%	\$47,789	\$49,801	\$2,012	4.21%	7.66¢
24									
25	5,000	300	@	30%	\$171,549	\$179,314	\$7,765	4.53%	11.95¢
26	5,000	400	@	30%	\$189,775	\$198,195	\$8,420	4.44%	9.91¢
27	5,000	500	@	25%	\$206,751	\$215,826	\$9,075	4.39%	8.63¢
28	5,000	600	@	25%	\$224,727	\$234,457	\$9,730	4.33%	7.82¢
29	5,000	650	@	25%	\$233,715	\$243,773	\$10,058	4.30%	7.50¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Primary Supply Rate - D11
Subtransmission 24 to 41.6kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 32 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$3.56
Voltage Level Discount (\$0.07)

Non-Capacity:

Power Supply Demand \$13.33
Voltage Level Discount (\$0.24)

Energy

On-Peak Rate \$0.04257
Off-Peak Rate \$0.03257
Voltage Discount (\$0.00062)

Surcharges:

PSCR \$0.00000
REPS >41,500kWh/month \$0.00
11,501-41,500 kWh/month \$0.00

Distribution

Service Charge: \$375

Distribution Charges:

Demand \$1.96

Energy

Substation Credit \$0.00

Surcharges:

NDS \$0.000882

Energy Waste Reduction \$1,238

IRM \$0.0312

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$9.19
Voltage Level Adjustment (\$0.19)

Non-Capacity:

Power Supply Demand \$8.35
Voltage Level Discount (\$0.17)

Energy

On-Peak Rate \$0.04388
Off-Peak Rate \$0.03388
Voltage Discount (\$0.00064)

Surcharges:

PSCR \$0.00000
REPS \$0.00
\$0.00

Distribution

Service Charge: \$375

Distribution Charges:

Demand \$1.82

Energy

Substation Credit \$0.00

Surcharges:

NDS \$0.000882

Energy Waste Reduction \$1,238

IRM \$0.0312

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line	Monthly	Hours			Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use		Percent	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	1,000	300	@	30%	\$30,934	\$31,781	\$847	2.74%	10.59¢
2	1,000	400	@	30%	\$34,517	\$35,493	\$976	2.83%	8.87¢
3	1,000	500	@	25%	\$37,850	\$38,955	\$1,105	2.92%	7.79¢
4	1,000	600	@	25%	\$41,383	\$42,617	\$1,234	2.98%	7.10¢
5	1,000	650	@	25%	\$43,150	\$44,448	\$1,298	3.01%	6.84¢
6									
7	5,000	300	@	30%	\$148,217	\$152,452	\$4,235	2.86%	10.16¢
8	5,000	400	@	30%	\$166,133	\$171,013	\$4,880	2.94%	8.55¢
9	5,000	500	@	25%	\$182,799	\$188,324	\$5,525	3.02%	7.53¢
10	5,000	600	@	25%	\$200,465	\$206,635	\$6,170	3.08%	6.89¢
11	5,000	650	@	25%	\$209,298	\$215,790	\$6,492	3.10%	6.64¢
12									
13	10,000	300	@	30%	\$294,821	\$303,291	\$8,470	2.87%	10.11¢
14	10,000	400	@	30%	\$330,653	\$340,413	\$9,760	2.95%	8.51¢
15	10,000	500	@	25%	\$363,985	\$375,035	\$11,050	3.04%	7.50¢
16	10,000	600	@	25%	\$399,317	\$411,657	\$12,340	3.09%	6.86¢
17	10,000	650	@	25%	\$416,983	\$429,968	\$12,985	3.11%	6.61¢
18									
19	50,000	300	@	30%	\$1,467,653	\$1,510,003	\$42,350	2.89%	10.07¢
20	50,000	400	@	30%	\$1,646,813	\$1,695,613	\$48,800	2.96%	8.48¢
21	50,000	500	@	25%	\$1,813,473	\$1,868,723	\$55,250	3.05%	7.47¢
22	50,000	600	@	25%	\$1,990,133	\$2,051,833	\$61,700	3.10%	6.84¢
23	50,000	650	@	25%	\$2,078,463	\$2,143,388	\$64,925	3.12%	6.60¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Primary Supply Rate - D11
Transmission 120kV and above

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 33 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$3.56
Voltage Level Discount (\$0.15)

Non-Capacity:

Power Supply Demand \$13.33
Voltage Level Discount (\$0.53)

Energy

On-Peak Rate \$0.04257
Off-Peak Rate \$0.03257
Voltage Discount (\$0.00138)

Surcharges:

PSCR \$0.00000
REPS >41,500kWh/month \$0.00
11,501-41,500 kWh/month \$0.00

Distribution

Service Charge: \$375
Distribution Charges:
Demand \$0.86
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0000

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$9.19
Voltage Level Adjustment (\$0.39)

Non-Capacity:

Power Supply Demand \$8.35
Voltage Level Discount (\$0.35)

Energy

On-Peak Rate \$0.04388
Off-Peak Rate \$0.03388
Voltage Level Adjustment (\$0.00143)

Surcharges:

PSCR \$0.00000
REPS \$0.00
\$0.00

Distribution

Service Charge: \$375
Distribution Charges:
Demand \$0.99
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0000

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line	Monthly	Hours			Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use		Percent	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	1,000	300	@	30%	\$29,205	\$30,303	\$1,098	3.76%	10.10¢
2	1,000	400	@	30%	\$32,712	\$33,936	\$1,224	3.74%	8.48¢
3	1,000	500	@	25%	\$35,969	\$37,319	\$1,350	3.75%	7.46¢
4	1,000	600	@	25%	\$39,426	\$40,902	\$1,476	3.74%	6.82¢
5	1,000	650	@	25%	\$41,155	\$42,694	\$1,539	3.74%	6.57¢
6									
7	5,000	300	@	30%	\$139,571	\$145,061	\$5,490	3.93%	9.67¢
8	5,000	400	@	30%	\$157,107	\$163,227	\$6,120	3.90%	8.16¢
9	5,000	500	@	25%	\$173,393	\$180,143	\$6,750	3.89%	7.21¢
10	5,000	600	@	25%	\$190,679	\$198,059	\$7,380	3.87%	6.60¢
11	5,000	650	@	25%	\$199,322	\$207,017	\$7,695	3.86%	6.37¢
12									
13	10,000	300	@	30%	\$277,529	\$288,509	\$10,980	3.96%	9.62¢
14	10,000	400	@	30%	\$312,601	\$324,841	\$12,240	3.92%	8.12¢
15	10,000	500	@	25%	\$345,173	\$358,673	\$13,500	3.91%	7.17¢
16	10,000	600	@	25%	\$379,745	\$394,505	\$14,760	3.89%	6.58¢
17	10,000	650	@	25%	\$397,031	\$412,421	\$15,390	3.88%	6.34¢
18									
19	50,000	300	@	30%	\$1,381,193	\$1,436,093	\$54,900	3.97%	9.57¢
20	50,000	400	@	30%	\$1,556,553	\$1,617,753	\$61,200	3.93%	8.09¢
21	50,000	500	@	25%	\$1,719,413	\$1,786,913	\$67,500	3.93%	7.15¢
22	50,000	600	@	25%	\$1,892,273	\$1,966,073	\$73,800	3.90%	6.55¢
23	50,000	650	@	25%	\$1,978,703	\$2,055,653	\$76,950	3.89%	6.33¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Primary Educational Institution Rate - D6.2
Primary Less Than 24kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 34 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$3.58
Voltage Level Adjustment

Non-Capacity:

Power Supply Demand \$10.04
Voltage Level Discount

Energy

On-Peak Rate \$0.04322
Off-Peak Rate \$0.04022
Voltage Discount \$0.00000

Surcharges:

PSCR \$0.00000
REPS >41,500kWh/month \$0.00
11,501-41,500 kWh/month \$0.00

Distribution

Service Charge: \$70
Distribution Charges:

Demand \$6.15
Energy

Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0727

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$10.79
Voltage Level Adjustment

Non-Capacity:

Power Supply Demand \$4.56
Voltage Level Discount

Energy

On-Peak Rate \$0.04837
Off-Peak Rate \$0.04537
Voltage Discount \$0.00000

Surcharges:

PSCR \$0.00000
REPS \$0.00
\$0.00

Distribution

Service Charge: \$70
Distribution Charges:

Demand \$6.66
Energy

Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
\$0.0727

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Monthly kW Demand	Hours Use		Percent	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	50	300	@	30%	\$2,930	\$3,119	\$189	6.46%	20.80¢
2	50	400	@	30%	\$3,140	\$3,355	\$215	6.85%	16.78¢
3	50	500	@	25%	\$3,346	\$3,587	\$241	7.19%	14.35¢
4	50	600	@	25%	\$3,556	\$3,822	\$266	7.50%	12.74¢
5	50	650	@	25%	\$3,660	\$3,940	\$279	7.63%	12.12¢
6									
7	100	300	@	30%	\$4,552	\$4,931	\$379	8.31%	16.44¢
8	100	400	@	30%	\$4,972	\$5,402	\$430	8.65%	13.51¢
9	100	500	@	25%	\$5,385	\$5,866	\$481	8.94%	11.73¢
10	100	600	@	25%	\$5,803	\$6,336	\$533	9.18%	10.56¢
11	100	650	@	25%	\$6,013	\$6,571	\$559	9.29%	10.11¢
12									
13	500	300	@	30%	\$17,530	\$19,422	\$1,893	10.80%	12.95¢
14	500	400	@	30%	\$19,630	\$21,780	\$2,150	10.95%	10.89¢
15	500	500	@	25%	\$21,692	\$24,100	\$2,408	11.10%	9.64¢
16	500	600	@	25%	\$23,785	\$26,450	\$2,665	11.20%	8.82¢
17	500	650	@	25%	\$24,831	\$27,625	\$2,794	11.25%	8.50¢
18									
19	1,000	300	@	30%	\$33,751	\$37,536	\$3,785	11.21%	12.51¢
20	1,000	400	@	30%	\$37,951	\$42,251	\$4,300	11.33%	10.56¢
21	1,000	500	@	25%	\$42,077	\$46,892	\$4,815	11.44%	9.38¢
22	1,000	600	@	25%	\$46,262	\$51,592	\$5,330	11.52%	8.60¢
23	1,000	650	@	25%	\$48,354	\$53,942	\$5,588	11.56%	8.30¢
24									
25	5,000	300	@	30%	\$163,524	\$182,449	\$18,925	11.57%	12.16¢
26	5,000	400	@	30%	\$184,525	\$206,025	\$21,500	11.65%	10.30¢
27	5,000	500	@	25%	\$205,151	\$229,226	\$24,075	11.74%	9.17¢
28	5,000	600	@	25%	\$226,077	\$252,727	\$26,650	11.79%	8.42¢
29	5,000	650	@	25%	\$236,540	\$264,478	\$27,938	11.81%	8.14¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Primary Educational Institution Rate - D6.2
Subtransmission 24 to 41.6kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 35 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$3.58
Voltage Level Discount (\$0.07)

Non-Capacity:

Power Supply Demand \$10.04
Voltage Level Discount (\$0.18)

Energy

On-Peak Rate \$0.04322
Off-Peak Rate \$0.04022
Voltage Discount (\$0.00073)

Surcharges:

PSCR \$0.00000
REPS >41,500kWh/month \$0.00
11,501-41,500 kWh/month \$0.00

Distribution

Service Charge: \$375
Distribution Charges:
Demand \$1.96
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0312

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$10.79
Voltage Level Adjustment (\$0.22)

Non-Capacity:

Power Supply Demand \$4.56
Voltage Level Discount (\$0.09)

Energy

On-Peak Rate \$0.04837
Off-Peak Rate \$0.04537
Voltage Discount (\$0.00082)

Surcharges:

PSCR \$0.00000
REPS \$0.00
\$0.00

Distribution

Service Charge: \$375
Distribution Charges:
Demand \$1.82
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
\$0.0312

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line	Monthly	Hours			Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use		Percent	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	1,000	300	@	30%	\$29,356	\$32,404	\$3,048	10.38%	10.80¢
2	1,000	400	@	30%	\$33,483	\$37,037	\$3,554	10.61%	9.26¢
3	1,000	500	@	25%	\$37,535	\$41,595	\$4,060	10.82%	8.32¢
4	1,000	600	@	25%	\$41,647	\$46,213	\$4,566	10.96%	7.70¢
5	1,000	650	@	25%	\$43,703	\$48,522	\$4,819	11.03%	7.46¢
6									
7	5,000	300	@	30%	\$140,327	\$155,567	\$15,240	10.86%	10.37¢
8	5,000	400	@	30%	\$160,963	\$178,733	\$17,770	11.04%	8.94¢
9	5,000	500	@	25%	\$181,224	\$201,524	\$20,300	11.20%	8.06¢
10	5,000	600	@	25%	\$201,785	\$224,615	\$22,830	11.31%	7.49¢
11	5,000	650	@	25%	\$212,065	\$236,160	\$24,095	11.36%	7.27¢
12									
13	10,000	300	@	30%	\$279,041	\$309,521	\$30,480	10.92%	10.32¢
14	10,000	400	@	30%	\$320,313	\$355,853	\$35,540	11.10%	8.90¢
15	10,000	500	@	25%	\$360,835	\$401,435	\$40,600	11.25%	8.03¢
16	10,000	600	@	25%	\$401,957	\$447,617	\$45,660	11.36%	7.46¢
17	10,000	650	@	25%	\$422,518	\$470,708	\$48,190	11.41%	7.24¢
18									
19	50,000	300	@	30%	\$1,388,753	\$1,541,153	\$152,400	10.97%	10.27¢
20	50,000	400	@	30%	\$1,595,113	\$1,772,813	\$177,700	11.14%	8.86¢
21	50,000	500	@	25%	\$1,797,723	\$2,000,723	\$203,000	11.29%	8.00¢
22	50,000	600	@	25%	\$2,003,333	\$2,231,633	\$228,300	11.40%	7.44¢
23	50,000	650	@	25%	\$2,106,138	\$2,347,088	\$240,950	11.44%	7.22¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Primary Educational Institution Rate - D6.2
Transmission 120kV and above

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 36 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$3.58
Voltage Level Discount (\$0.15)

Non-Capacity:

Power Supply Demand \$10.04
Voltage Level Discount (\$0.40)

Energy

On-Peak Rate \$0.04322
Off-Peak Rate \$0.04022
Voltage Discount (\$0.00162)

Surcharges:

PSCR \$0.00000
REPS >41,500kWh/month \$0.00
11,501-41,500 kWh/month \$0.00

Distribution

Service Charge: \$375
Distribution Charges:
Demand \$0.86
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0000

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand \$10.79
Voltage Level Adjustment (\$0.45)

Non-Capacity:

Power Supply Demand \$4.56
Voltage Level Discount (\$0.19)

Energy

On-Peak Rate \$0.04837
Off-Peak Rate \$0.04537
Voltage Discount (\$0.00182)

Surcharges:

PSCR \$0.00000
REPS \$0.00
\$0.00

Distribution

Service Charge: \$375
Distribution Charges:
Demand \$0.99
Energy
Substation Credit \$0.00

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.0000

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line	Monthly	Hours			Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use		Percent	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	1,000	300	@	30%	\$27,658	\$30,913	\$3,255	11.77%	10.30¢
2	1,000	400	@	30%	\$31,696	\$35,446	\$3,750	11.83%	8.86¢
3	1,000	500	@	25%	\$35,659	\$39,904	\$4,245	11.90%	7.98¢
4	1,000	600	@	25%	\$39,682	\$44,422	\$4,740	11.94%	7.40¢
5	1,000	650	@	25%	\$41,694	\$46,681	\$4,988	11.96%	7.18¢
6									
7	5,000	300	@	30%	\$131,836	\$148,111	\$16,275	12.34%	9.87¢
8	5,000	400	@	30%	\$152,027	\$170,777	\$18,750	12.33%	8.54¢
9	5,000	500	@	25%	\$171,843	\$193,068	\$21,225	12.35%	7.72¢
10	5,000	600	@	25%	\$191,959	\$215,659	\$23,700	12.35%	7.19¢
11	5,000	650	@	25%	\$202,017	\$226,954	\$24,938	12.34%	6.98¢
12									
13	10,000	300	@	30%	\$262,059	\$294,609	\$32,550	12.42%	9.82¢
14	10,000	400	@	30%	\$302,441	\$339,941	\$37,500	12.40%	8.50¢
15	10,000	500	@	25%	\$342,073	\$384,523	\$42,450	12.41%	7.69¢
16	10,000	600	@	25%	\$382,305	\$429,705	\$47,400	12.40%	7.16¢
17	10,000	650	@	25%	\$402,421	\$452,296	\$49,875	12.39%	6.96¢
18									
19	50,000	300	@	30%	\$1,303,843	\$1,466,593	\$162,750	12.48%	9.78¢
20	50,000	400	@	30%	\$1,505,753	\$1,693,253	\$187,500	12.45%	8.47¢
21	50,000	500	@	25%	\$1,703,913	\$1,916,163	\$212,250	12.46%	7.66¢
22	50,000	600	@	25%	\$1,905,073	\$2,142,073	\$237,000	12.44%	7.14¢
23	50,000	650	@	25%	\$2,005,653	\$2,255,028	\$249,375	12.43%	6.94¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible Supply Rate - D8
Primary Less Than 24kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand	\$1.62
Voltage Level Discount	\$0.00
Product Protection	\$3.56
Voltage Level Discount	\$0.00

Non-Capacity:

Power Supply Demand	\$8.50
Voltage Level Discount	\$0.00
Product Protection	\$13.33
Voltage Level Discount	\$0.00

Energy

On-Peak Rate	\$0.04257
Off-Peak Rate	\$0.03257
Voltage Discount	\$0.00000

Surcharges:

PSCR	\$0.00000
REPS >41,500kWh/month	\$0.00
11,501-41,500 kWh/month	\$0.00

Distribution

Service Charge:	\$70
Distribution Charges:	
Demand	\$6.15

Substation Credit \$0.00

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.0727

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand	\$4.24
Voltage Level Adjustment	\$0.00
Product Protection	\$9.19
Voltage Level Adjustment	\$0.00

Non-Capacity:

Power Supply Demand	\$6.00
Voltage Level Adjustment	\$0.00
Product Protection	\$8.35
Voltage Level Adjustment	\$0.00

Energy

On-Peak Rate	\$0.04388
Off-Peak Rate	\$0.03388
Voltage Discount	\$0.00000

Surcharges:

PSCR	\$0.00000
REPS	\$0.00
	\$0.00

Distribution

Service Charge:	\$70
Distribution Charges:	
Demand	\$6.66

Substation Credit \$0.00

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.0727

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Monthly kW Demand	Hours Use		Percent	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	50	300	@	30%	\$2,740	\$2,796	\$56	2.06%	18.64¢
2	50	400	@	25%	\$2,912	\$2,975	\$63	2.16%	14.87¢
3	50	500	@	25%	\$3,092	\$3,161	\$70	2.25%	12.64¢
4	50	600	@	25%	\$3,271	\$3,347	\$76	2.33%	11.16¢
5									
6	100	300	@	30%	\$4,171	\$4,284	\$113	2.71%	14.28¢
7	100	400	@	25%	\$4,516	\$4,642	\$126	2.79%	11.60¢
8	100	500	@	25%	\$4,875	\$5,014	\$139	2.85%	10.03¢
9	100	600	@	25%	\$5,235	\$5,387	\$152	2.91%	8.98¢
10									
11	500	300	@	30%	\$15,624	\$16,189	\$564	3.61%	10.79¢
12	500	400	@	25%	\$17,347	\$17,977	\$630	3.63%	8.99¢
13	500	500	@	25%	\$19,144	\$19,840	\$695	3.63%	7.94¢
14	500	600	@	25%	\$20,942	\$21,703	\$761	3.63%	7.23¢
15									
16	1,000	300	@	30%	\$29,940	\$31,069	\$1,129	3.77%	10.36¢
17	1,000	400	@	25%	\$33,385	\$34,645	\$1,260	3.77%	8.66¢
18	1,000	500	@	25%	\$36,981	\$38,372	\$1,391	3.76%	7.67¢
19	1,000	600	@	25%	\$40,576	\$42,098	\$1,522	3.75%	7.02¢
20									
21	5,000	300	@	30%	\$144,469	\$150,114	\$5,645	3.91%	10.01¢
22	5,000	400	@	25%	\$161,695	\$167,995	\$6,300	3.90%	8.40¢
23	5,000	500	@	25%	\$179,671	\$186,626	\$6,955	3.87%	7.47¢
24	5,000	600	@	25%	\$197,647	\$205,257	\$7,610	3.85%	6.84¢

1. The above bill comparison includes 20% product protection to better represent the total site bill versus only the interruptible portion.
2. The Hours-Use categories were changed to better reflect actual load characteristics

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible Supply Rate - D8
Subtransmission 24 to 41.6kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand	\$1.62
Voltage Level Discount	(\$0.03)
Product Protection	\$3.56
Voltage Level Discount	(\$0.07)

Non-Capacity:

Power Supply Demand	\$8.50
Voltage Level Discount	(\$0.15)
Product Protection	\$13.33
Voltage Level Discount	(\$0.24)

Energy

On-Peak Rate	\$0.04257
Off-Peak Rate	\$0.03257
Voltage Discount	(\$0.00062)

Surcharges:

PSCR	\$0.00000
REPS >41,500kWh/month	\$0.00
11,501-41,500 kWh/	\$0.00

Distribution

Service Charge:	\$375
Distribution Charges:	
Demand	\$1.96

Substation Credit

	\$0.00
Surcharges:	
NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.0312

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand	\$4.24
Voltage Level Adjustment	(\$0.09)
Product Protection	\$9.19
Voltage Level Adjustment	(\$0.19)

Non-Capacity:

Power Supply Demand	\$6.00
Voltage Level Adjustment	(\$0.12)
Product Protection	\$8.35
Voltage Level Adjustment	(\$0.17)

Energy

On-Peak Rate	\$0.04388
Off-Peak Rate	\$0.03388
Voltage Discount	(\$0.00064)

Surcharges:

PSCR	\$0.00000
REPS	\$0.00
	\$0.00

Distribution

Service Charge:	\$375
Distribution Charges:	
Demand	\$1.82

Substation Credit

	\$0.00
Surcharges:	
NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.0312

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Monthly kW Demand	Hours Use		Percent	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	1,000	300	@	30%	\$25,622	\$26,061	\$439	1.71%	8.69¢
2	1,000	400	@	25%	\$29,005	\$29,573	\$568	1.96%	7.39¢
3	1,000	500	@	25%	\$32,538	\$33,235	\$697	2.14%	6.65¢
4	1,000	600	@	25%	\$36,071	\$36,897	\$826	2.29%	6.15¢
5									
6	5,000	300	@	30%	\$121,657	\$123,852	\$2,195	1.80%	8.26¢
7	5,000	400	@	25%	\$138,573	\$141,413	\$2,840	2.05%	7.07¢
8	5,000	500	@	25%	\$156,239	\$159,724	\$3,485	2.23%	6.39¢
9	5,000	600	@	25%	\$173,905	\$178,035	\$4,130	2.37%	5.93¢
10									
11	10,000	300	@	30%	\$241,701	\$246,091	\$4,390	1.82%	8.20¢
12	10,000	400	@	25%	\$275,533	\$281,213	\$5,680	2.06%	7.03¢
13	10,000	500	@	25%	\$310,865	\$317,835	\$6,970	2.24%	6.36¢
14	10,000	600	@	25%	\$346,197	\$354,457	\$8,260	2.39%	5.91¢
15									
16	50,000	300	@	30%	\$1,202,053	\$1,224,003	\$21,950	1.83%	8.16¢
17	50,000	400	@	25%	\$1,371,213	\$1,399,613	\$28,400	2.07%	7.00¢
18	50,000	500	@	25%	\$1,547,873	\$1,582,723	\$34,850	2.25%	6.33¢
19	50,000	600	@	25%	\$1,724,533	\$1,765,833	\$41,300	2.39%	5.89¢

1. The above bill comparison includes 20% product protection to better represent the total site bill versus only the interruptible portion.
2. The Hours-Use categories were changed to better reflect actual load characteristics

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible Supply Rate - D8
Transmission 120kV and above

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand	\$1.62
Voltage Level Discount	(\$0.07)
Product Protection	\$3.56
Voltage Level Discount	(\$0.15)

Non-Capacity:

Power Supply Demand	\$8.50
Voltage Level Discount	(\$0.33)
Product Protection	\$13.33
Voltage Level Discount	(\$0.53)

Energy

On-Peak Rate	\$0.04257
Off-Peak Rate	\$0.03257
Voltage Discount	(\$0.00138)

Surcharges:

PSCR	\$0.00000
REPS >41,500kWh/month	\$0.00
11,501-41,500 kWh	\$0.00

Distribution

Service Charge:	\$375
Distribution Charges:	
Demand	\$0.86

Substation Credit \$0.00

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.0000

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Power Supply Demand	\$4.24
Voltage Level Adjustment	(\$0.18)
Product Protection	\$9.19
Voltage Level Adjustment	(\$0.39)

Non-Capacity:

Power Supply Demand	\$6.00
Voltage Level Adjustment	(\$0.25)
Product Protection	\$8.35
Voltage Level Adjustment	(\$0.35)

Energy

On-Peak Rate	\$0.04388
Off-Peak Rate	\$0.03388
Voltage Discount	(\$0.00143)

Surcharges:

PSCR	\$0.00000
REPS	\$0.00
	\$0.00

Distribution

Service Charge:	\$375
Distribution Charges:	
Demand	\$0.99

Substation Credit \$0.00

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.0000

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Monthly kW Demand	Hours Use		Percent	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	1,000	300	@	30%	\$24,013	\$24,711	\$698	2.91%	8.24¢
2	1,000	400	@	25%	\$27,320	\$28,144	\$824	3.02%	7.04¢
3	1,000	500	@	25%	\$30,777	\$31,727	\$950	3.09%	6.35¢
4	1,000	600	@	25%	\$34,234	\$35,310	\$1,076	3.14%	5.89¢
5									
6	5,000	300	@	30%	\$113,611	\$117,101	\$3,490	3.07%	7.81¢
7	5,000	400	@	25%	\$130,147	\$134,267	\$4,120	3.17%	6.71¢
8	5,000	500	@	25%	\$147,433	\$152,183	\$4,750	3.22%	6.09¢
9	5,000	600	@	25%	\$164,719	\$170,099	\$5,380	3.27%	5.67¢
10									
11	10,000	300	@	30%	\$225,609	\$232,589	\$6,980	3.09%	7.75¢
12	10,000	400	@	25%	\$258,681	\$266,921	\$8,240	3.19%	6.67¢
13	10,000	500	@	25%	\$293,253	\$302,753	\$9,500	3.24%	6.06¢
14	10,000	600	@	25%	\$327,825	\$338,585	\$10,760	3.28%	5.64¢
15									
16	50,000	300	@	30%	\$1,121,593	\$1,156,493	\$34,900	3.11%	7.71¢
17	50,000	400	@	25%	\$1,286,953	\$1,328,153	\$41,200	3.20%	6.64¢
18	50,000	500	@	25%	\$1,459,813	\$1,507,313	\$47,500	3.25%	6.03¢
19	50,000	600	@	25%	\$1,632,673	\$1,686,473	\$53,800	3.30%	5.62¢

1. The above bill comparison includes 20% product protection to better represent the total site bill versus only the interruptible portion.
2. The Hours-Use categories were changed to better reflect actual load characteristics

**Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
All Electric School Buildings Rate - D10
November Thru May**

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 40 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.00094

Non-Capacity:

Energy Charge \$0.07430

Surcharges:

PSCR \$0.00000

REPS >41,500kWh/month \$0.00

11,501-41,500 kWh/month \$0.00

Distribution

Service Charge \$70

Distribution Energy Charge \$0.01968

Surcharges:

NDS \$0.000882

Energy Waste Reduction \$1,238

IRM \$0.000233

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01445

Non-Capacity:

Energy Charge \$0.06384

Surcharges:

PSCR \$0.00000

REPS \$0.00

\$0.00

Distribution

Service Charge \$70

Distribution Energy Charge \$0.01973

Surcharges:

NDS \$0.000882

Energy Waste Reduction \$1,238

IRM \$0.000233

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase		(f) Proposed Unit Cost
				Amount	Percent	
1	40,000	\$5,149	\$5,273	\$124.00	2.41%	13.18¢
2	50,000	\$6,110	\$6,265	\$155.00	2.54%	12.53¢
3	60,000	\$7,070	\$7,256	\$186.00	2.63%	12.09¢
4	70,000	\$8,030	\$8,247	\$217.00	2.70%	11.78¢
5	80,000	\$8,991	\$9,239	\$248.00	2.76%	11.55¢
6	90,000	\$9,951	\$10,230	\$279.00	2.80%	11.37¢
7	100,000	\$10,911	\$11,221	\$310.00	2.84%	11.22¢
8	110,000	\$11,872	\$12,213	\$341.00	2.87%	11.10¢
9	120,000	\$12,832	\$13,204	\$372.00	2.90%	11.00¢
10	130,000	\$13,793	\$14,196	\$403.00	2.92%	10.92¢
11	140,000	\$14,753	\$15,187	\$434.00	2.94%	10.85¢

**Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
All Electric School Buildings Rate - D10
June Thru October**

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 41 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.02107

Non-Capacity:

Energy Charge \$0.07430

Surcharges:

PSCR \$0.00000

REPS >41,500kWh/month \$0.00

11,501-41,500 kWh/month \$0.00

Distribution

Service Charge \$70

Distribution Energy Charge \$0.01968

Surcharges:

NDS \$0.000882

Energy Waste Reduction \$1,238

IRM \$0.000233

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.03458

Non-Capacity:

Energy Charge \$0.06384

Surcharges:

PSCR \$0.00000

REPS \$0.00

\$0.00

Distribution

Service Charge \$70

Distribution Energy Charge \$0.01973

Surcharges:

NDS \$0.000882

Energy Waste Reduction \$1,238

\$0.000233

Line No.	(a) Monthly kWh Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase Amount	(e) Percent	(f) Proposed Unit Cost
1	40,000	\$5,955	\$6,079	\$124.00	2.08%	15.20¢
2	60,000	\$8,278	\$8,464	\$186.00	2.25%	14.11¢
3	80,000	\$10,601	\$10,849	\$248.00	2.34%	13.56¢
4	100,000	\$12,924	\$13,234	\$310.00	2.40%	13.23¢
5	120,000	\$15,248	\$15,620	\$372.00	2.44%	13.02¢
6	140,000	\$17,571	\$18,005	\$434.00	2.47%	12.86¢
7	160,000	\$19,894	\$20,390	\$496.00	2.49%	12.74¢
8	180,000	\$22,218	\$22,776	\$558.00	2.51%	12.65¢
9	200,000	\$24,541	\$25,161	\$620.00	2.53%	12.58¢
10	220,000	\$26,864	\$27,546	\$682.00	2.54%	12.52¢
11	240,000	\$29,188	\$29,932	\$744.00	2.55%	12.47¢
12	260,000	\$31,511	\$32,317	\$806.00	2.56%	12.43¢
13	280,000	\$33,834	\$34,702	\$868.00	2.57%	12.39¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
XL High Load Factor Rate - D13
Primary

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 42 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01514

Non-Capacity:

Energy Charge \$0.03430

Transmission Charge \$0.00304

Surcharges:

REPS \$0.00

Distribution

Service Charge \$70

Distribution Energy Charge \$0.00936

Administration Charge \$0.00015

Surcharges:

Energy Waste Reduction \$1,237.99

IRM \$0.000133

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01514

Non-Capacity:

Energy Charge \$0.03287

Transmission Charge \$0.00308

Surcharges:

REPS \$0.00

Distribution

Service Charge \$70

Distribution Energy Charge \$0.01014

Administration Charge \$0.00015

Surcharges:

Energy Waste Reduction \$1,237.99

IRM \$0.000133

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
				Amount	Percent	
1	27,000,000	\$1,678,629	\$1,662,159	-\$16,470	-0.98%	6.16¢
2	29,000,000	\$1,802,875	\$1,785,185	-\$17,690	-0.98%	6.16¢
3	31,000,000	\$1,927,121	\$1,908,211	-\$18,910	-0.98%	6.16¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
XL High Load Factor Rate - D13
Subtransmission

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 43 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01514

Non-Capacity:

Energy Charge \$0.03430

Transmission Charge \$0.00304

Surcharges:

REPS \$0.00

Distribution

Service Charge \$375

Distribution Energy Charge \$0.00298

Administration Charge \$0.00015

Surcharges:

Energy Waste Reduction \$1,237.99

IRM \$0.000057

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01514

Non-Capacity:

Energy Charge \$0.03287

Transmission Charge \$0.00308

Surcharges:

REPS \$0.00

Distribution

Service Charge \$375

Distribution Energy Charge \$0.00277

Administration Charge \$0.00015

Surcharges:

Energy Waste Reduction \$1,237.99

IRM \$0.000057

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
				Amount	Percent	
1	27,000,000	\$1,504,622	\$1,461,422	-\$43,200	-2.87%	5.41¢
2	29,000,000	\$1,615,956	\$1,569,556	-\$46,400	-2.87%	5.41¢
3	31,000,000	\$1,727,290	\$1,677,690	-\$49,600	-2.87%	5.41¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
XL High Load Factor Rate - D13
Transmission

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 44 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01514

Non-Capacity:

Energy Charge \$0.03430

Transmission Charge \$0.00304

Surcharges:

REPS \$0.00

Distribution

Service Charge \$375

Distribution Energy Charge \$0.00131

Administration Charge \$0.00015

Surcharges:

Energy Waste Reduction \$1,237.99

IRM \$0.000000

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy Charge \$0.01514

Non-Capacity:

Energy Charge \$0.03287

Transmission Charge \$0.00308

Surcharges:

REPS \$0.00

Distribution

Service Charge \$375

Distribution Energy Charge \$0.00151

Administration Charge \$0.00015

Surcharges:

Energy Waste Reduction \$1,237.99

IRM \$0.000000

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly kWh Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
				Amount	Percent	
1	27,000,000	\$1,457,993	\$1,425,863	-\$32,130	-2.20%	5.28¢
2	29,000,000	\$1,565,873	\$1,531,363	-\$34,510	-2.20%	5.28¢
3	31,000,000	\$1,673,753	\$1,636,863	-\$36,890	-2.20%	5.28¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Alternative Metal Melting - Standard Contract Rider No. R1.1
Secondary Voltage Level

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 45 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.00706
Excess Hrs. Use \$0.00267

Non-Capacity:

Energy \$0.05251

Surcharges:

PSCR \$0.00000
REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.05288
Excess Hrs. Use \$0.05288

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.000555

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.01789
Excess Hrs. Use \$0.00676

Non-Capacity:

Energy \$0.04892

Surcharges:

PSCR \$0.00000
REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.06156
Excess Hrs. Use \$0.06156

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
\$0.000555

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
					Amount	Percent	
1	50	100	\$1,807	\$1,887	\$79.60	4.40%	37.74¢
2	50	200	\$2,355	\$2,480	\$125.50	5.33%	24.80¢
3	50	300	\$2,902	\$3,074	\$171.40	5.91%	20.49¢
4	50	400	\$3,450	\$3,667	\$217.30	6.30%	18.34¢
5	50	500	\$3,997	\$4,261	\$263.20	6.58%	17.04¢
6	50	600	\$4,545	\$4,854	\$309.10	6.80%	16.18¢
7	50	700	\$5,092	\$5,447	\$355.00	6.97%	15.56¢
8							
9	500	100	\$6,932	\$7,728	\$796.00	11.48%	15.46¢
10	500	200	\$12,407	\$13,662	\$1,255.00	10.12%	13.66¢
11	500	300	\$17,882	\$19,596	\$1,714.00	9.59%	13.06¢
12	500	400	\$23,357	\$25,530	\$2,173.00	9.30%	12.76¢
13	500	500	\$28,832	\$31,464	\$2,632.00	9.13%	12.59¢
14	500	600	\$34,307	\$37,398	\$3,091.00	9.01%	12.47¢
15	500	700	\$39,781	\$43,331	\$3,550.00	8.92%	12.38¢
16							
17	1000	100	\$12,627	\$14,219	\$1,592.00	12.61%	14.22¢
18	1,000	200	\$23,576	\$26,086	\$2,510.00	10.65%	13.04¢
19	1,000	300	\$34,526	\$37,954	\$3,428.00	9.93%	12.65¢
20	1,000	400	\$45,476	\$49,822	\$4,346.00	9.56%	12.46¢
21	1,000	500	\$56,425	\$61,689	\$5,264.00	9.33%	12.34¢
22	1,000	600	\$67,375	\$73,557	\$6,182.00	9.18%	12.26¢
23	1,000	700	\$78,325	\$85,425	\$7,100.00	9.06%	12.20¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Alternative Metal Melting - Standard Contract Rider No. R1.1
Primary Less Than 24kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 46 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.00525
Excess Hrs. Use \$0.00191

Non-Capacity:

Energy \$0.05251

Surcharges:

PSCR \$0.00000
REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.01832
Excess Hrs. Use \$0.01832

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.000229

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.01330
Excess Hrs. Use \$0.00484

Non-Capacity:

Energy \$0.04892

Surcharges:

PSCR \$0.00000
REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.02015
Excess Hrs. Use \$0.02015

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.000229

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	50	100	\$1,624	\$1,655	\$31.45	1.94%	33.11¢
2	50	200	\$1,993	\$2,031	\$37.30	1.87%	20.31¢
3	50	300	\$2,362	\$2,406	\$43.15	1.83%	16.04¢
4	50	400	\$2,732	\$2,781	\$49.00	1.79%	13.90¢
5	50	500	\$3,101	\$3,156	\$54.85	1.77%	12.62¢
6	50	600	\$3,470	\$3,531	\$60.70	1.75%	11.77¢
7	50	700	\$3,839	\$3,906	\$66.55	1.73%	11.16¢
8							
9	500	100	\$5,098	\$5,412	\$314.50	6.17%	10.82¢
10	500	200	\$8,790	\$9,163	\$373.00	4.24%	9.16¢
11	500	300	\$12,483	\$12,914	\$431.50	3.46%	8.61¢
12	500	400	\$16,175	\$16,665	\$490.00	3.03%	8.33¢
13	500	500	\$19,868	\$20,416	\$548.50	2.76%	8.17¢
14	500	600	\$23,560	\$24,167	\$607.00	2.58%	8.06¢
15	500	700	\$27,253	\$27,918	\$665.50	2.44%	7.98¢
16							
17	1,000	100	\$8,957	\$9,586	\$629.00	7.02%	9.59¢
18	1,000	200	\$16,342	\$17,088	\$746.00	4.56%	8.54¢
19	1,000	300	\$23,727	\$24,590	\$863.00	3.64%	8.20¢
20	1,000	400	\$31,112	\$32,092	\$980.00	3.15%	8.02¢
21	1,000	500	\$38,497	\$39,594	\$1,097.00	2.85%	7.92¢
22	1,000	600	\$45,883	\$47,097	\$1,214.00	2.65%	7.85¢
23	1,000	700	\$53,268	\$54,599	\$1,331.00	2.50%	7.80¢
24							
25	5,000	100	\$39,833	\$42,978	\$3,145.00	7.90%	8.60¢
26	5,000	200	\$76,759	\$80,489	\$3,730.00	4.86%	8.05¢
27	5,000	300	\$113,684	\$117,999	\$4,315.00	3.80%	7.87¢
28	5,000	400	\$150,610	\$155,510	\$4,900.00	3.25%	7.78¢
29	5,000	500	\$187,535	\$193,020	\$5,485.00	2.92%	7.72¢
30	5,000	600	\$224,461	\$230,531	\$6,070.00	2.70%	7.68¢
31	5,000	700	\$261,386	\$268,041	\$6,655.00	2.55%	7.66¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Alternative Metal Melting - Standard Contract Rider No. R1.1
Subtransmission 24 to 41.6kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 47 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.00512
Excess Hrs. Use \$0.00178

Non-Capacity:

Energy \$0.05251

Surcharges:

PSCR \$0.00000
REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.00677
Excess Hrs. Use \$0.00677

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.000104

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.01297
Excess Hrs. Use \$0.00451

Non-Capacity:

Energy \$0.04892

Surcharges:

PSCR \$0.00000
REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.00532
Excess Hrs. Use \$0.00532

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM \$0.000104

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
					Amount	Percent	
1	50	100	\$1,565	\$1,579	\$14.05	0.90%	31.58¢
2	50	200	\$1,875	\$1,878	\$2.50	0.13%	18.78¢
3	50	300	\$2,185	\$2,176	-\$9.05	-0.41%	14.51¢
4	50	400	\$2,496	\$2,475	-\$20.60	-0.83%	12.38¢
5	50	500	\$2,806	\$2,774	-\$32.15	-1.15%	11.09¢
6	50	600	\$3,116	\$3,072	-\$43.70	-1.40%	10.24¢
7	50	700	\$3,426	\$3,371	-\$55.25	-1.61%	9.63¢
8							
9	500	100	\$4,507	\$4,648	\$140.50	3.12%	9.30¢
10	500	200	\$7,610	\$7,635	\$25.00	0.33%	7.63¢
11	500	300	\$10,712	\$10,621	-\$90.50	-0.84%	7.08¢
12	500	400	\$13,814	\$13,608	-\$206.00	-1.49%	6.80¢
13	500	500	\$16,916	\$16,595	-\$321.50	-1.90%	6.64¢
14	500	600	\$20,019	\$19,582	-\$437.00	-2.18%	6.53¢
15	500	700	\$23,121	\$22,569	-\$552.50	-2.39%	6.45¢
16							
17	1,000	100	\$7,777	\$8,058	\$281.00	3.61%	8.06¢
18	1,000	200	\$13,981	\$14,031	\$50.00	0.36%	7.02¢
19	1,000	300	\$20,186	\$20,005	-\$181.00	-0.90%	6.67¢
20	1,000	400	\$26,390	\$25,978	-\$412.00	-1.56%	6.49¢
21	1,000	500	\$32,595	\$31,952	-\$643.00	-1.97%	6.39¢
22	1,000	600	\$38,800	\$37,926	-\$874.00	-2.25%	6.32¢
23	1,000	700	\$45,004	\$43,899	-\$1,105.00	-2.46%	6.27¢
24							
25	5,000	100	\$33,931	\$35,336	\$1,405.00	4.14%	7.07¢
26	5,000	200	\$64,954	\$65,204	\$250.00	0.38%	6.52¢
27	5,000	300	\$95,977	\$95,072	-\$905.00	-0.94%	6.34¢
28	5,000	400	\$127,000	\$124,940	-\$2,060.00	-1.62%	6.25¢
29	5,000	500	\$158,023	\$154,808	-\$3,215.00	-2.03%	6.19¢
30	5,000	600	\$189,046	\$184,676	-\$4,370.00	-2.31%	6.16¢
31	5,000	700	\$220,069	\$214,544	-\$5,525.00	-2.51%	6.13¢
32							
33	10,000	100	\$66,624	\$69,434	\$2,810.00	4.22%	6.94¢
34	10,000	200	\$128,670	\$129,170	\$500.00	0.39%	6.46¢
35	10,000	300	\$190,716	\$188,906	-\$1,810.00	-0.95%	6.30¢
36	10,000	400	\$252,762	\$248,642	-\$4,120.00	-1.63%	6.22¢
37	10,000	500	\$314,808	\$308,378	-\$6,430.00	-2.04%	6.17¢
38	10,000	600	\$376,854	\$368,114	-\$8,740.00	-2.32%	6.14¢
39	10,000	700	\$438,900	\$427,850	-\$11,050.00	-2.52%	6.11¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Alternative Metal Melting - Standard Contract Rider No. R1.1
Transmission 120kV and above

Case No.: U-21534
 Exhibit: A-16
 Schedule: F4
 Witness: A. Willis
 Page: 48 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.00434
 Excess Hrs. Use \$0.00144

Non-Capacity:

Energy \$0.05251

Surcharges:

PSCR \$0.00000
 REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.00274
 Excess Hrs. Use \$0.00274

Surcharges:

NDS \$0.000882
 Energy Waste Reduction \$1,238
 IRM \$0.000000

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use \$0.01100
 Excess Hrs. Use \$0.00365

Non-Capacity:

Energy \$0.04892

Surcharges:

PSCR \$0.00000
 REPS \$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use \$0.00600
 Excess Hrs. Use \$0.00600

Surcharges:

NDS \$0.000882
 Energy Waste Reduction \$1,238
 IRM \$0.000000

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Monthly	Hours	Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	50	100	\$1,540	\$1,572	\$31.65	2.05%	31.44¢
2	50	200	\$1,828	\$1,869	\$41.05	2.25%	18.69¢
3	50	300	\$2,116	\$2,167	\$50.45	2.38%	14.44¢
4	50	400	\$2,404	\$2,464	\$59.85	2.49%	12.32¢
5	50	500	\$2,692	\$2,761	\$69.25	2.57%	11.04¢
6	50	600	\$2,980	\$3,058	\$78.65	2.64%	10.19¢
7	50	700	\$3,268	\$3,356	\$88.05	2.69%	9.59¢
8							
9	500	100	\$4,262	\$4,578	\$316.50	7.43%	9.16¢
10	500	200	\$7,140	\$7,551	\$410.50	5.75%	7.55¢
11	500	300	\$10,019	\$10,523	\$504.50	5.04%	7.02¢
12	500	400	\$12,897	\$13,496	\$598.50	4.64%	6.75¢
13	500	500	\$15,776	\$16,468	\$692.50	4.39%	6.59¢
14	500	600	\$18,655	\$19,441	\$786.50	4.22%	6.48¢
15	500	700	\$21,533	\$22,414	\$880.50	4.09%	6.40¢
16							
17	1,000	100	\$7,285	\$7,918	\$633.00	8.69%	7.92¢
18	1,000	200	\$13,042	\$13,863	\$821.00	6.29%	6.93¢
19	1,000	300	\$18,800	\$19,809	\$1,009.00	5.37%	6.60¢
20	1,000	400	\$24,557	\$25,754	\$1,197.00	4.87%	6.44¢
21	1,000	500	\$30,314	\$31,699	\$1,385.00	4.57%	6.34¢
22	1,000	600	\$36,071	\$37,644	\$1,573.00	4.36%	6.27¢
23	1,000	700	\$41,828	\$43,589	\$1,761.00	4.21%	6.23¢
24							
25	5,000	100	\$31,474	\$34,639	\$3,165.00	10.06%	6.93¢
26	5,000	200	\$60,260	\$64,365	\$4,105.00	6.81%	6.44¢
27	5,000	300	\$89,046	\$94,091	\$5,045.00	5.67%	6.27¢
28	5,000	400	\$117,832	\$123,817	\$5,985.00	5.08%	6.19¢
29	5,000	500	\$146,618	\$153,543	\$6,925.00	4.72%	6.14¢
30	5,000	600	\$175,404	\$183,269	\$7,865.00	4.48%	6.11¢
31	5,000	700	\$204,190	\$212,995	\$8,805.00	4.31%	6.09¢
32							
33	10,000	100	\$61,710	\$68,040	\$6,330.00	10.26%	6.80¢
34	10,000	200	\$119,282	\$127,492	\$8,210.00	6.88%	6.37¢
35	10,000	300	\$176,854	\$186,944	\$10,090.00	5.71%	6.23¢
36	10,000	400	\$234,426	\$246,396	\$11,970.00	5.11%	6.16¢
37	10,000	500	\$291,998	\$305,848	\$13,850.00	4.74%	6.12¢
38	10,000	600	\$349,570	\$365,300	\$15,730.00	4.50%	6.09¢
39	10,000	700	\$407,142	\$424,752	\$17,610.00	4.33%	6.07¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Electric Process Heat - Standard Contract Rider No. R1.2
Secondary Voltage Level

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 49 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.00706
Excess Hrs. Use	\$0.00267

Non-Capacity:

Energy	\$0.05251

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.05288
Excess Hrs. Use	\$0.05288

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000555

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.01789
Excess Hrs. Use	\$0.00676

Non-Capacity:

Energy	\$0.04892

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.06156
Excess Hrs. Use	\$0.06156

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000555

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	50	100	\$1,807	\$1,887	\$79.60	4.40%	37.74¢
2	50	200	\$2,355	\$2,480	\$125.50	5.33%	24.80¢
3	50	300	\$2,902	\$3,074	\$171.40	5.91%	20.49¢
4	50	400	\$3,450	\$3,667	\$217.30	6.30%	18.34¢
5	50	500	\$3,997	\$4,261	\$263.20	6.58%	17.04¢
6	50	600	\$4,545	\$4,854	\$309.10	6.80%	16.18¢
7	50	700	\$5,092	\$5,447	\$355.00	6.97%	15.56¢
8							
9	500	100	\$6,932	\$7,728	\$796.00	11.48%	15.46¢
10	500	200	\$12,407	\$13,662	\$1,255.00	10.12%	13.66¢
11	500	300	\$17,882	\$19,596	\$1,714.00	9.59%	13.06¢
12	500	400	\$23,357	\$25,530	\$2,173.00	9.30%	12.76¢
13	500	500	\$28,832	\$31,464	\$2,632.00	9.13%	12.59¢
14	500	600	\$34,307	\$37,398	\$3,091.00	9.01%	12.47¢
15	500	700	\$39,781	\$43,331	\$3,550.00	8.92%	12.38¢
16							
17	1000	100	\$12,627	\$14,219	\$1,592.00	12.61%	14.22¢
18	1,000	200	\$23,576	\$26,086	\$2,510.00	10.65%	13.04¢
19	1,000	300	\$34,526	\$37,954	\$3,428.00	9.93%	12.65¢
20	1,000	400	\$45,476	\$49,822	\$4,346.00	9.56%	12.46¢
21	1,000	500	\$56,425	\$61,689	\$5,264.00	9.33%	12.34¢
22	1,000	600	\$67,375	\$73,557	\$6,182.00	9.18%	12.26¢
23	1,000	700	\$78,325	\$85,425	\$7,100.00	9.06%	12.20¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Electric Process Heat - Standard Contract Rider No. R1.2
Primary Less Than 24kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 50 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.00525
Excess Hrs. Use	\$0.00191

Non-Capacity:

Energy	\$0.05251

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.01832
Excess Hrs. Use	\$0.01832

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000229

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.01330
Excess Hrs. Use	\$0.00484

Non-Capacity:

Energy	\$0.04892

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.02015
Excess Hrs. Use	\$0.02015

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000229

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
1	50	100	\$1,624	\$1,655	\$31.45	1.94%	33.11¢
2	50	200	\$1,993	\$2,031	\$37.30	1.87%	20.31¢
3	50	300	\$2,362	\$2,406	\$43.15	1.83%	16.04¢
4	50	400	\$2,732	\$2,781	\$49.00	1.79%	13.90¢
5	50	500	\$3,101	\$3,156	\$54.85	1.77%	12.62¢
6	50	600	\$3,470	\$3,531	\$60.70	1.75%	11.77¢
7	50	700	\$3,839	\$3,906	\$66.55	1.73%	11.16¢
8							
9	500	100	\$5,098	\$5,412	\$314.50	6.17%	10.82¢
10	500	200	\$8,790	\$9,163	\$373.00	4.24%	9.16¢
11	500	300	\$12,483	\$12,914	\$431.50	3.46%	8.61¢
12	500	400	\$16,175	\$16,665	\$490.00	3.03%	8.33¢
13	500	500	\$19,868	\$20,416	\$548.50	2.76%	8.17¢
14	500	600	\$23,560	\$24,167	\$607.00	2.58%	8.06¢
15	500	700	\$27,253	\$27,918	\$665.50	2.44%	7.98¢
16							
17	1,000	100	\$8,957	\$9,586	\$629.00	7.02%	9.59¢
18	1,000	200	\$16,342	\$17,088	\$746.00	4.56%	8.54¢
19	1,000	300	\$23,727	\$24,590	\$863.00	3.64%	8.20¢
20	1,000	400	\$31,112	\$32,092	\$980.00	3.15%	8.02¢
21	1,000	500	\$38,497	\$39,594	\$1,097.00	2.85%	7.92¢
22	1,000	600	\$45,883	\$47,097	\$1,214.00	2.65%	7.85¢
23	1,000	700	\$53,268	\$54,599	\$1,331.00	2.50%	7.80¢
24							
25	5,000	100	\$39,833	\$42,978	\$3,145.00	7.90%	8.60¢
26	5,000	200	\$76,759	\$80,489	\$3,730.00	4.86%	8.05¢
27	5,000	300	\$113,684	\$117,999	\$4,315.00	3.80%	7.87¢
28	5,000	400	\$150,610	\$155,510	\$4,900.00	3.25%	7.78¢
29	5,000	500	\$187,535	\$193,020	\$5,485.00	2.92%	7.72¢
30	5,000	600	\$224,461	\$230,531	\$6,070.00	2.70%	7.68¢
31	5,000	700	\$261,386	\$268,041	\$6,655.00	2.55%	7.66¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Electric Process Heat - Standard Contract Rider No. R1.2
Subtransmission 24 to 41.6kV

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
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Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.00512
Excess Hrs. Use	\$0.00178

Non-Capacity:

Energy	\$0.05251

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.00677
Excess Hrs. Use	\$0.00677

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000104

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.01297
Excess Hrs. Use	\$0.00451

Non-Capacity:

Energy	\$0.04892

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.00532
Excess Hrs. Use	\$0.00532

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000104

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase		Proposed Unit Cost
					Amount	Percent	
1	50	100	\$1,565	\$1,579	\$14.05	0.90%	31.58¢
2	50	200	\$1,875	\$1,878	\$2.50	0.13%	18.78¢
3	50	300	\$2,185	\$2,176	-\$9.05	-0.41%	14.51¢
4	50	400	\$2,496	\$2,475	-\$20.60	-0.83%	12.38¢
5	50	500	\$2,806	\$2,774	-\$32.15	-1.15%	11.09¢
6	50	600	\$3,116	\$3,072	-\$43.70	-1.40%	10.24¢
7	50	700	\$3,426	\$3,371	-\$55.25	-1.61%	9.63¢
8							
9	500	100	\$4,507	\$4,648	\$140.50	3.12%	9.30¢
10	500	200	\$7,610	\$7,635	\$25.00	0.33%	7.63¢
11	500	300	\$10,712	\$10,621	-\$90.50	-0.84%	7.08¢
12	500	400	\$13,814	\$13,608	-\$206.00	-1.49%	6.80¢
13	500	500	\$16,916	\$16,595	-\$321.50	-1.90%	6.64¢
14	500	600	\$20,019	\$19,582	-\$437.00	-2.18%	6.53¢
15	500	700	\$23,121	\$22,569	-\$552.50	-2.39%	6.45¢
16							
17	1,000	100	\$7,777	\$8,058	\$281.00	3.61%	8.06¢
18	1,000	200	\$13,981	\$14,031	\$50.00	0.36%	7.02¢
19	1,000	300	\$20,186	\$20,005	-\$181.00	-0.90%	6.67¢
20	1,000	400	\$26,390	\$25,978	-\$412.00	-1.56%	6.49¢
21	1,000	500	\$32,595	\$31,952	-\$643.00	-1.97%	6.39¢
22	1,000	600	\$38,800	\$37,926	-\$874.00	-2.25%	6.32¢
23	1,000	700	\$45,004	\$43,899	-\$1,105.00	-2.46%	6.27¢
24							
25	5,000	100	\$33,931	\$35,336	\$1,405.00	4.14%	7.07¢
26	5,000	200	\$64,954	\$65,204	\$250.00	0.38%	6.52¢
27	5,000	300	\$95,977	\$95,072	-\$905.00	-0.94%	6.34¢
28	5,000	400	\$127,000	\$124,940	-\$2,060.00	-1.62%	6.25¢
29	5,000	500	\$158,023	\$154,808	-\$3,215.00	-2.03%	6.19¢
30	5,000	600	\$189,046	\$184,676	-\$4,370.00	-2.31%	6.16¢
31	5,000	700	\$220,069	\$214,544	-\$5,525.00	-2.51%	6.13¢
32							
33	10,000	100	\$66,624	\$69,434	\$2,810.00	4.22%	6.94¢
34	10,000	200	\$128,670	\$129,170	\$500.00	0.39%	6.46¢
35	10,000	300	\$190,716	\$188,906	-\$1,810.00	-0.95%	6.30¢
36	10,000	400	\$252,762	\$248,642	-\$4,120.00	-1.63%	6.22¢
37	10,000	500	\$314,808	\$308,378	-\$6,430.00	-2.04%	6.17¢
38	10,000	600	\$376,854	\$368,114	-\$8,740.00	-2.32%	6.14¢
39	10,000	700	\$438,900	\$427,850	-\$11,050.00	-2.52%	6.11¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Electric Process Heat - Standard Contract Rider No. R1.2
Transmission 120kV and above

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 52 of 53

Present Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.00434
Excess Hrs. Use	\$0.00144

Non-Capacity:

Energy	\$0.05251

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.00274
Excess Hrs. Use	\$0.00274

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000000

Proposed Rates and Current Surcharges:

Power Supply

Capacity:

Energy

1st 100 Hrs. Use	\$0.01100
Excess Hrs. Use	\$0.00365

Non-Capacity:

Energy	\$0.04892

Surcharges:

PSCR	\$0.00000
REPS	\$0.00

Distribution

Distribution Charges:

1st 100 Hrs. Use	\$0.00600
Excess Hrs. Use	\$0.00600

Surcharges:

NDS	\$0.000882
Energy Waste Reduction	\$1,238
IRM	\$0.000000

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Monthly	Hours	Present Net	Proposed Net	Increase		Proposed
No.	kW Demand	Use	Monthly Bill	Monthly Bill	Amount	Percent	Unit Cost
1	50	100	\$1,540	\$1,572	\$31.65	2.05%	31.44¢
2	50	200	\$1,828	\$1,869	\$41.05	2.25%	18.69¢
3	50	300	\$2,116	\$2,167	\$50.45	2.38%	14.44¢
4	50	400	\$2,404	\$2,464	\$59.85	2.49%	12.32¢
5	50	500	\$2,692	\$2,761	\$69.25	2.57%	11.04¢
6	50	600	\$2,980	\$3,058	\$78.65	2.64%	10.19¢
7	50	700	\$3,268	\$3,356	\$88.05	2.69%	9.59¢
8							
9	500	100	\$4,262	\$4,578	\$316.50	7.43%	9.16¢
10	500	200	\$7,140	\$7,551	\$410.50	5.75%	7.55¢
11	500	300	\$10,019	\$10,523	\$504.50	5.04%	7.02¢
12	500	400	\$12,897	\$13,496	\$598.50	4.64%	6.75¢
13	500	500	\$15,776	\$16,468	\$692.50	4.39%	6.59¢
14	500	600	\$18,655	\$19,441	\$786.50	4.22%	6.48¢
15	500	700	\$21,533	\$22,414	\$880.50	4.09%	6.40¢
16							
17	1,000	100	\$7,285	\$7,918	\$633.00	8.69%	7.92¢
18	1,000	200	\$13,042	\$13,863	\$821.00	6.29%	6.93¢
19	1,000	300	\$18,800	\$19,809	\$1,009.00	5.37%	6.60¢
20	1,000	400	\$24,557	\$25,754	\$1,197.00	4.87%	6.44¢
21	1,000	500	\$30,314	\$31,699	\$1,385.00	4.57%	6.34¢
22	1,000	600	\$36,071	\$37,644	\$1,573.00	4.36%	6.27¢
23	1,000	700	\$41,828	\$43,589	\$1,761.00	4.21%	6.23¢
24							
25	5,000	100	\$31,474	\$34,639	\$3,165.00	10.06%	6.93¢
26	5,000	200	\$60,260	\$64,365	\$4,105.00	6.81%	6.44¢
27	5,000	300	\$89,046	\$94,091	\$5,045.00	5.67%	6.27¢
28	5,000	400	\$117,832	\$123,817	\$5,985.00	5.08%	6.19¢
29	5,000	500	\$146,618	\$153,543	\$6,925.00	4.72%	6.14¢
30	5,000	600	\$175,404	\$183,269	\$7,865.00	4.48%	6.11¢
31	5,000	700	\$204,190	\$212,995	\$8,805.00	4.31%	6.09¢
32							
33	10,000	100	\$61,710	\$68,040	\$6,330.00	10.26%	6.80¢
34	10,000	200	\$119,282	\$127,492	\$8,210.00	6.88%	6.37¢
35	10,000	300	\$176,854	\$186,944	\$10,090.00	5.71%	6.23¢
36	10,000	400	\$234,426	\$246,396	\$11,970.00	5.11%	6.16¢
37	10,000	500	\$291,998	\$305,848	\$13,850.00	4.74%	6.12¢
38	10,000	600	\$349,570	\$365,300	\$15,730.00	4.50%	6.09¢
39	10,000	700	\$407,142	\$424,752	\$17,610.00	4.33%	6.07¢

Michigan Public Service Commission
DTE Electric Company
Comparison of Present and Proposed Monthly Bills
Interruptible Supply Rider - Standard Contract Rider No. R10

Case No.: U-21534
Exhibit: A-16
Schedule: F4
Witness: A. Willis
Page: 53 of 53

Present Rates and Current Surcharges:

Power Supply

Non-Capacity:

Administrative Charge \$0.00000
MISO Energy Charge \$0.03935
Net Trans MISO Mkt \$0.00767

Voltage Level Service Adder:

Primary - 5.50% of HPSC \$0.00259
Subtransmission - 3.73% of HPSC \$0.00175
Transmission - 1.56% of HPSC \$0.00073

Surcharges:

REPS \$0.00

Distribution

Service Charge PV: \$70
Service Charge SV: \$375
Service Charge TV: \$375
Distribution Charges:
Primary \$6.15

Subtransmission \$1.96

Transmission \$0.86

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM
Primary \$0.0727
Subtrans \$0.0312
Transmission \$0.0000

Proposed Rates and Current Surcharges:

Power Supply

Non-Capacity:

Administrative Charge \$0.00000
MISO Energy Charge \$0.03935
Net Trans MISO Mkt \$0.00769

Voltage Level Service Adder:

Primary - 5.50% of HPSC \$0.00259
Subtransmission - 3.73% of HPSC \$0.00175
Transmission - 1.56% of HPSC \$0.00073

Surcharges:

REPS \$0.00

Distribution

Service Charge: \$70
Service Charge SV: \$375
Service Charge TV: \$375
Distribution Charges:
Demand \$6.66

Demand \$1.82

Demand \$0.99

Surcharges:

NDS \$0.000882
Energy Waste Reduction \$1,238
IRM
Primary \$0.0727
Subtrans \$0.0312
Transmission \$0.0000

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Monthly kW Demand	Hours Use	Present Net Monthly Bill	Proposed Net Monthly Bill	Increase Amount	Percent	Proposed Unit Cost
Primary Less Than 24kV							
1	10,000	200	\$164,511	\$169,653	\$5,142	3.13%	8.48¢
2	10,000	300	\$214,999	\$220,163	\$5,163	2.40%	7.34¢
3	10,000	400	\$265,487	\$270,672	\$5,184	1.95%	6.77¢
4	10,000	500	\$315,975	\$321,181	\$5,205	1.65%	6.42¢
Subtransmission 24 to 41.6kV							
5	10,000	200	\$120,837	\$119,478	-\$1,359	-1.12%	5.97¢
6	10,000	300	\$170,493	\$169,155	-\$1,338	-0.78%	5.64¢
7	10,000	400	\$220,148	\$218,831	-\$1,317	-0.60%	5.47¢
8	10,000	500	\$269,804	\$268,508	-\$1,296	-0.48%	5.37¢
Transmission 120kV and Up							
9	10,000	200	\$107,484	\$108,825	\$1,341	1.25%	5.44¢
10	10,000	300	\$156,120	\$157,480	\$1,361	0.87%	5.25¢
11	10,000	400	\$204,755	\$206,136	\$1,381	0.67%	5.15¢
12	10,000	500	\$253,391	\$254,792	\$1,402	0.55%	5.10¢

Michigan Public Service Commission
DTE Electric Company
Calculation of Voltage Level Distribution Charges

Case No.: U-21534
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Schedule: F5
Witness: A. Willis
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Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Exh A-16, Sch F-1.2 Line 28	(a) + (b)			(c) - (d) - (e)		(f) ÷ (g)
		Present Base Delivery Revenue (\$000)	Revenue Def/(Suf) (\$000)	Target Base Revenue (\$000)	Proposed Service Charge Revenue (\$000)	Substation Credit (\$000)	Target Distribution Demand Rev (\$000)	Distribution Demand kW	Primary Voltage Distribution Charge \$/kW
1	Primary Voltage								
2	Rate								
3	D11	129,470						20,713,457	
4	D6.2	16,557						2,655,419	
5	D8	6,913						1,106,505	
6	D10	701						101,535	
7	R1.1/R1.2	5,771						937,466	
8	R3	492						78,089	
9	R10	1,110						178,736	
10	Primary Voltage Total	161,015	13,242	174,257	2,567	0	171,690	25,771,207	6.66
11									
12		Present							Subtransmission
13		Base							Voltage
14		Delivery							Distribution
15		Revenue							Charge
16		(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	kW	\$/kW
17	Subtransmission Voltage								
18	Rate								
19	D11	7,200						3,677,382	
20	D6.2	1,983						999,979	
21	D8	409						196,004	
22	R1.1/R1.2	520						219,761	
23	R3	968						483,801	
24	R10	149						65,584	
25	Subtransmission Voltage Total	11,229	(871)	10,358	526	(439)	10,271	5,642,510	1.82
26									
27		Present							Transmission
28		Base							Voltage
29		Delivery							Distribution
30		Revenue							Charge
31		(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	kW	\$/kW
32	Transmission Voltage								
33	Rate								
34	D11	7,993						10,297,494	
35	D6.2	0						0	
36	D8	170						277,821	
37	R1.1/R1.2	174						379,377	
38	R3	84						92,427	
39	R10	2,991						3,790,403	
40	Transmission Voltage Total	11,411	2,105	13,515	471	(1,663)	14,708	14,837,522	0.99

Michigan Public Service Commission
DTE Electric Company
Calculation of Nuclear Surcharge

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Line No.	(a) Description	(b) Amount (\$000)	(c) Source
1	Proposed Nuclear Surcharge Revenue:		
2	Site Security & Radiation Protection	\$ 31,203	Exh A-20, Sch J1, L2
3	Nuclear Decommissioning Funding	2,867	Exh A-20, Sch J1, L3
4	Low Level Radioactive Waste Disposal Funding	6,000	Exh A-20, Sch J1, L4
6	Total Proposed Nuclear Surcharge Revenue	\$ 40,070	Exh A-20, Sch J1, L5
7			
8	Forecast Jurisdictional Sales (MWh), excluding D13	43,981,994	Exh A-16, Sch F2, Page 4
9	Proposed Nuclear Surcharge	0.000911 \$/kWh	L6 ÷ L8

Michigan Public Service Commission
DTE Electric Company
Rider 18 Outflow Credits

Case No.: U-21534
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Witness: A. Willis
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Line No	(a) Rate Schedule	(b) Non-Capacity Rate	(c) Capacity Rate	(d) (b) + (c) Outflow Credit	(e) Unit
1	<u>RESIDENTIAL</u>				
2	D1/D1.6				
3	First 17 KWH/Day	\$0.06237	\$0.02932	\$0.09169	per kWh
4	Excess	\$0.06237	\$0.04227	\$0.10464	per kWh
5	D1.1				
6	Summer	0.04870	0.02799	\$0.07669	per kWh
7	Winter	0.04870	0.00694	\$0.05564	per kWh
8	D1.2				
9	Summer On Peak	\$0.11955	\$0.04474	\$0.16429	per kWh
10	Summer Off Peak	\$0.04025	\$0.01506	\$0.05531	per kWh
11	Winter On Peak	\$0.10098	\$0.03779	\$0.13877	per kWh
12	Winter Off Peak	\$0.03867	\$0.01447	\$0.05314	per kWh
13	D1.7				
14	Summer On Peak	\$0.09310	\$0.05086	\$0.14396	per kWh
15	Summer Off Peak	\$0.03084	\$0.01685	\$0.04769	per kWh
16	Winter On Peak	\$0.04023	\$0.02197	\$0.06220	per kWh
17	Winter Off Peak	\$0.03161	\$0.01727	\$0.04888	per kWh
18	D1.8				
19	Off Peak	\$0.03098	\$0.01678	\$0.04776	per kWh
20	Mid Peak	\$0.06004	\$0.03252	\$0.09256	per kWh
21	On Peak	\$0.11702	\$0.06229	\$0.17931	per kWh
22	Critical Peak	\$0.11702	\$0.83298	\$0.95000	per kWh
23	D1.9				
24	On Peak	\$0.11700	\$0.06387	\$0.18087	per kWh
25	Off Peak	\$0.02924	\$0.01598	\$0.04522	per kWh
26	D1.11				
27	June-Sept On Peak	\$0.09748	\$0.05325	\$0.15073	per kWh
28	June-Sept Off Peak	\$0.05873	\$0.03208	\$0.09081	per kWh
29	Oct-May On Peak	\$0.06875	\$0.03755	\$0.10630	per kWh
30	Oct-May Off Peak	\$0.05873	\$0.03208	\$0.09081	per kWh
31	D1.13				
32	June-Sept On Peak	\$0.10846	\$0.05925	\$0.16771	per kWh
33	June-Sept Off Peak	\$0.07298	\$0.03987	\$0.11285	per kWh
34	June-Sept Super Off Peak	\$0.04609	\$0.02518	\$0.07127	per kWh
35	Oct-May On Peak	\$0.06186	\$0.03379	\$0.09565	per kWh
36	Oct-May Off Peak	\$0.05552	\$0.03033	\$0.08585	per kWh
37	Oct-May Super Off Peak	\$0.04609	\$0.02518	\$0.07127	per kWh
38	D2				
39	Summer First 17 kWh/day	\$0.05498	\$0.02817	\$0.08315	per kWh
40	Summer Excess	\$0.05498	\$0.04027	\$0.09525	per kWh
41	Winter First 20 kWh/day	\$0.05498	\$0.01660	\$0.07158	per kWh
42	Winter Excess	\$0.05498	\$0.00649	\$0.06147	per kWh
43	D5				
44	All Outflow	\$0.03303	\$0.01805	\$0.05108	per kWh
45					
46	<u>COMMERCIAL SECONDARY</u>				
47	D1.1 Commercial				
48	Summer	\$0.05025	\$0.02713	\$0.07738	per kWh
49	Winter	\$0.05025	\$0.01215	\$0.06240	per kWh
50	D1.7 Commercial				
51	Summer On Peak	\$0.03586	\$0.01591	\$0.05177	per kWh
52	Summer Off Peak	\$0.03276	\$0.01453	\$0.04729	per kWh
53	Winter On Peak	\$0.03354	\$0.01488	\$0.04842	per kWh
54	Winter Off Peak	\$0.03354	\$0.01488	\$0.04842	per kWh
55	D1.8				
56	Off Peak	\$0.03311	\$0.01457	\$0.04768	per kWh
57	Mid Peak	\$0.06505	\$0.02862	\$0.09367	per kWh
58	On Peak	\$0.12163	\$0.05271	\$0.17434	per kWh
59	Critical Peak	\$0.12163	\$0.82837	\$0.95000	per kWh
60	D1.9				
61	On Peak	\$0.11700	\$0.06387	\$0.18087	per kWh
62	Off Peak	\$0.02924	\$0.01598	\$0.04522	per kWh
63	D3				
64	All Outflow	\$0.05870	\$0.02605	\$0.08475	per kWh
65	D3.2				
66	All Outflow	\$0.05764	\$0.02426	\$0.08190	per kWh
67	D3.3				
68	All Outflow	\$0.04905	\$0.02176	\$0.07081	per kWh
69	D3.11				
70	June-Sept On Peak	\$0.09236	\$0.04098	\$0.13334	per kWh
71	June-Sept Off Peak	\$0.05509	\$0.02444	\$0.07953	per kWh
72	Oct-May On Peak	\$0.05894	\$0.02615	\$0.08509	per kWh
73	Oct-May Off Peak	\$0.05509	\$0.02444	\$0.07953	per kWh
74	D4				
75	First 200 kWh per kW	\$0.04169	\$0.00000	\$0.04169	per kWh
76	Excess	\$0.03219	\$0.00000	\$0.03219	per kWh
77	Demand	\$8.07	\$9.18	\$17.25	per kW
78	D5				
79	All Outflow	\$0.03457	\$0.01534	\$0.04991	per kWh
80	E1.1				
81	All Outflow	\$0.04045	\$0.01792	\$0.05837	per kWh

Michigan Public Service Commission
DTE Electric Company
Rider 18 Outflow Credits

Case No.: A. Willis
Exhibit: A-16
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Witness: A. Willis
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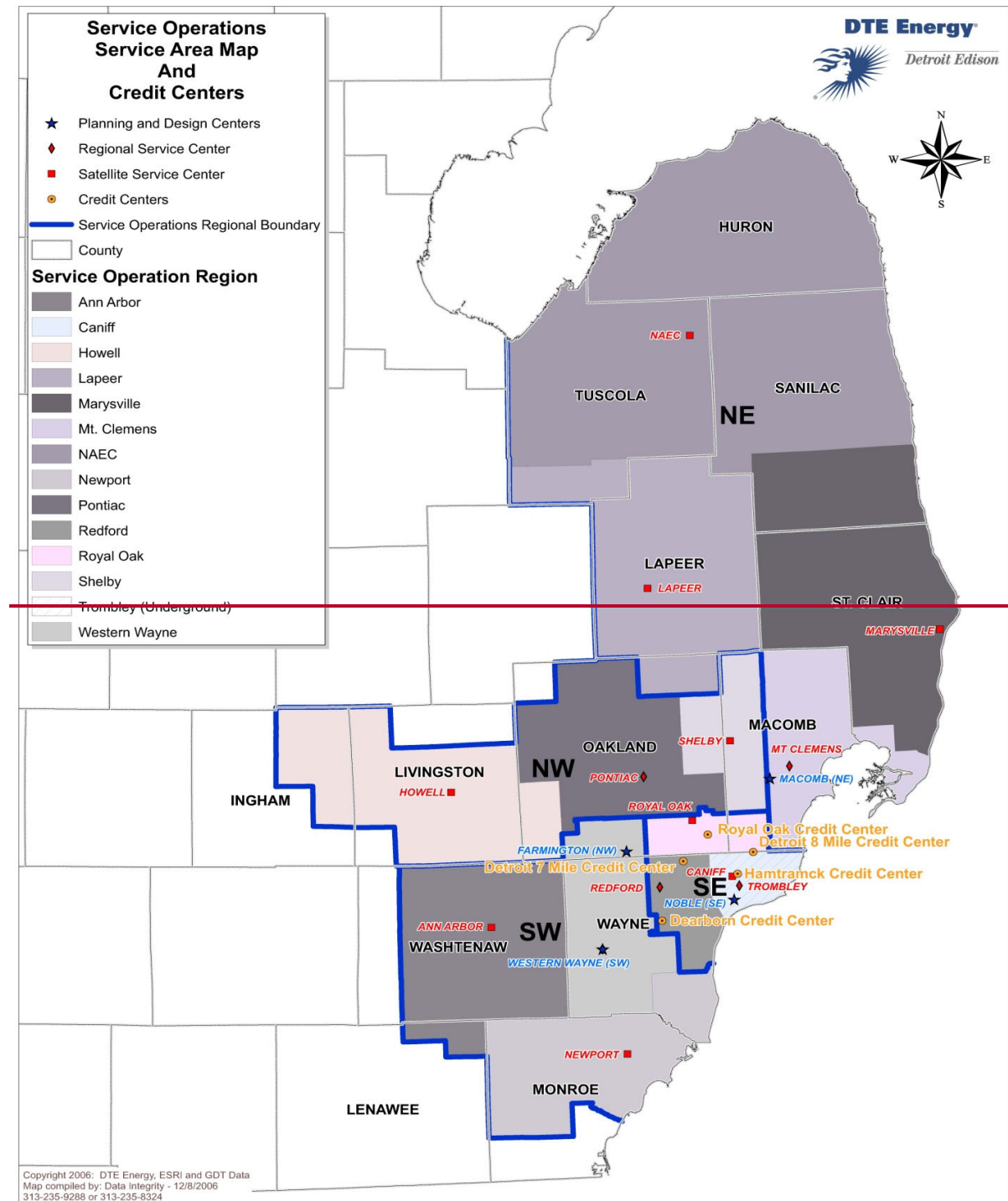
	(a)	(b)	(c)	(d)	(e)
Line No	Rate Schedule	Non-Capacity Rate	Capacity Rate	Outflow Credit	Unit
1	PRIMARY				
2	D11				
3	Primary				
4	On Peak	\$0.04388		\$0.04388	per kWh
5	Off Peak	\$0.03388		\$0.03388	per kWh
6	Demand	\$8.35	\$9.19	\$17.54	per kW
7	Subtransmission				
8	On Peak	\$0.04324		\$0.04324	per kWh
9	Off Peak	\$0.03324		\$0.03324	per kWh
10	Demand	\$8.18	\$9.00	\$17.18	per kW
11	Transmission				
12	On Peak	\$0.04245		\$0.04245	per kWh
13	Off Peak	\$0.03245		\$0.03245	per kWh
14	Demand	\$8.00	\$8.80	\$16.80	per kW
15	D6.2				
16	Primary				
17	On Peak	\$0.04837		\$0.04837	per kWh
18	Off Peak	\$0.04537		\$0.04537	per kWh
19	Demand	\$4.56	\$10.79	\$15.35	per kW
20	Subtransmission				
21	On Peak	\$0.04755		\$0.04755	per kWh
22	Off Peak	\$0.04455		\$0.04455	per kWh
23	Demand	\$4.47	\$10.57	\$15.04	per kW
24	Transmission				
25	On Peak	\$0.04655		\$0.04655	per kWh
26	Off Peak	\$0.04355		\$0.04355	per kWh
27	Demand	\$4.37	\$10.34	\$14.71	per kW
28	D8				
29	Primary				
30	On Peak	\$0.04388		\$0.04388	per kWh
31	Off Peak	\$0.03388		\$0.03388	per kWh
32	Demand	\$6.00	\$4.24	\$10.24	per kW
33	Subtransmission				
34	On Peak	\$0.04324		\$0.04324	per kWh
35	Off Peak	\$0.03324		\$0.03324	per kWh
36	Demand	\$5.88	\$4.15	\$10.03	per kW
37	Transmission				
38	On Peak	\$0.04245		\$0.04245	per kWh
39	Off Peak	\$0.03245		\$0.03245	per kWh
40	Demand	\$5.75	\$4.06	\$9.81	per kW
41	D10				
42	Summer	\$0.06384	\$0.03458	\$0.09842	per kWh
43	Winter	\$0.06384	\$0.01445	\$0.07829	per kWh
44	D13				
45	All Outflow	\$0.03595	\$0.01514	\$0.05109	per kWh
46	D14				
47	Primary				
48	June-Sept On Peak	\$0.08024	\$0.02649	\$0.10673	per kWh
49	June-Sept Off Peak	\$0.04775	\$0.01576	\$0.06351	per kWh
50	Oct-May On Peak	\$0.05547	\$0.01831	\$0.07378	per kWh
51	Oct-May Off Peak	\$0.04775	\$0.01576	\$0.06351	per kWh
52	Subtransmission				
53	June-Sept On Peak	\$0.07932	\$0.02619	\$0.10551	per kWh
54	June-Sept Off Peak	\$0.04683	\$0.01546	\$0.06229	per kWh
55	Oct-May On Peak	\$0.05455	\$0.01801	\$0.07256	per kWh
56	Oct-May Off Peak	\$0.04683	\$0.01546	\$0.06229	per kWh
57	Transmission				
58	June-Sept On Peak	\$0.07819	\$0.02581	\$0.10400	per kWh
59	June-Sept Off Peak	\$0.04570	\$0.01508	\$0.06078	per kWh
60	Oct-May On Peak	\$0.05342	\$0.01763	\$0.07105	per kWh
61	Oct-May Off Peak	\$0.04570	\$0.01508	\$0.06078	per kWh

Case No.: U-21534
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Witness: A. Willis
R. A. Bellini
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DTE Electric Company

Proposed Tariff Sheets – 12 Months Ending December 31, 2025

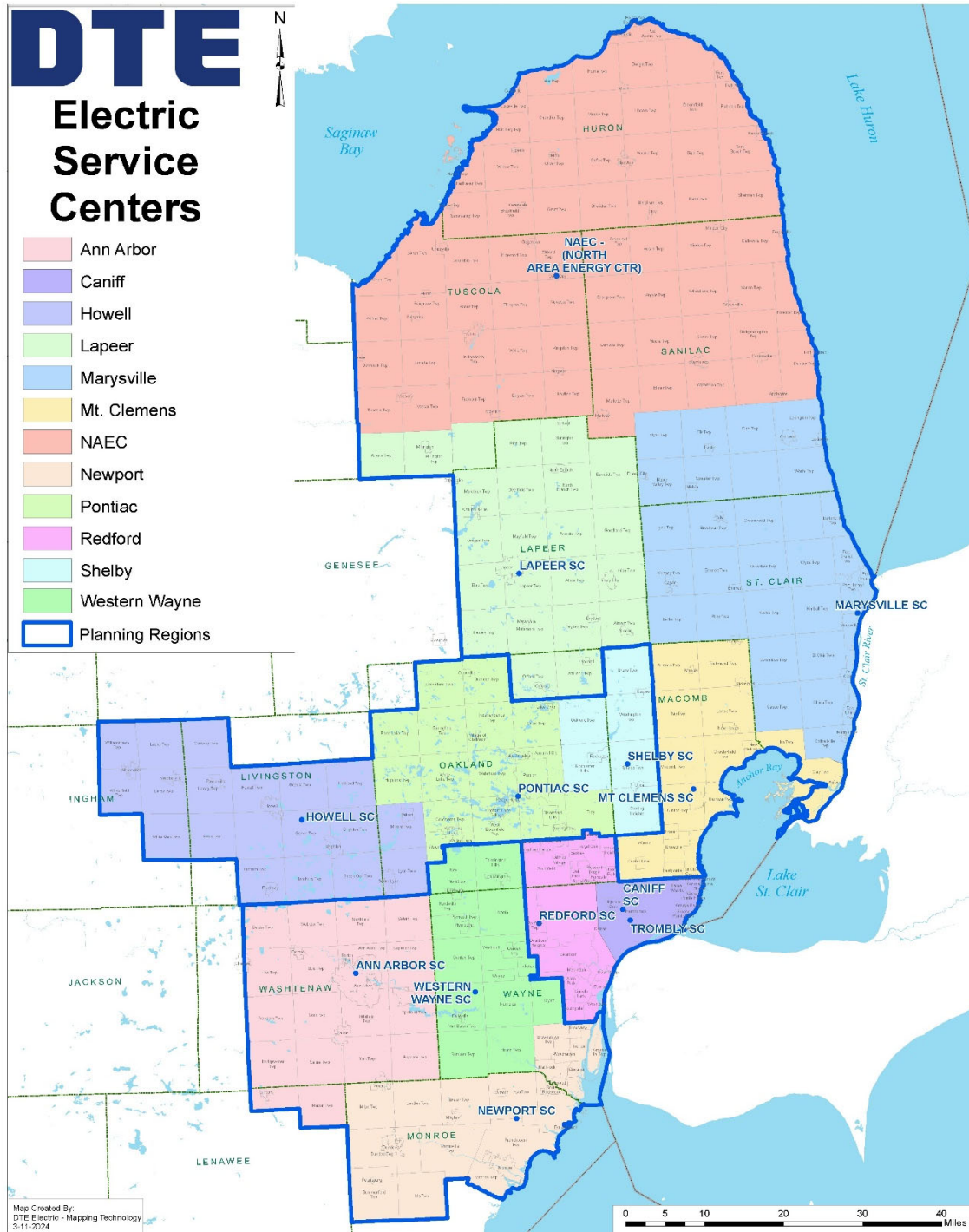
**For all pricing changes on the following tariff sheets,
refer to Exhibit A-16, Schedule F3**



Issued _____, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

See Willis Direct Testimony Page
46, Line 9 though Line 10



Issued _____, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs
Detroit, Michigan

See Willis Direct Testimony Page 46
Line 9 though Line 10

(Continued from Sheet No. C-26.00)

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

C6.1 Extension of Service (Contd.)

- (13) The applicant shall furnish without cost to the Company, all necessary rights-of-way and line clearance permits in a form satisfactory to the Company. The Company will provide the necessary easement forms, and solicit their execution. The applicant(s), as a condition of service, will be ultimately responsible for obtaining all easements and permits as required by the Company, for construction, operation, maintenance and protection of the facilities to be constructed. Where State or Federal lands are to be crossed to extend service to an applicant or group of applicants, the additional costs incurred by the Company for rights-of-way and permit fees shall be borne by the applicant(s). If the applicant is unable to secure satisfactory easements and/or permits, the Company shall extend its facilities along an alternate route selected by the Company. The applicant will be required to make a non-refundable contribution in aid of construction for all additional costs incurred.
- (14) Scheduling of construction shall be done on a basis mutually agreeable to the Company and the applicant. The Company reserves the right not to begin construction until the customer has demonstrated to the Company's satisfaction his intent to proceed in good faith with installation of his facilities by acquiring property ownership, obtaining all necessary permits, starting construction, and/or, in the case of mobile homes, meeting the Company's requirements for permanency.
- (15) The Company reserves the right to make the final determination of selection, application, location, routing and design of its facilities. Where excessive construction costs are incurred by the Company at the request of the customer, the customer may be required to make a non-refundable contribution in aid of construction to the Company for such excess costs.

~~(16) Beginning in May 2019, the Company will waive the contribution in aid of construction calculated pursuant to Section C6 for the term of the Company's Charging Forward program, in order to construct and extend its facilities to serve new loads associated with three categories of electric vehicle charging stations. These categories include: (1) DC Fast Charging stations, (2) Level 2 Charging stations, and (3) Fleet Charging stations.~~

C6.2 Overhead Extension Policy

A Customers on Rates D1 and D2.

- (1) Overhead Extension Policy - Application for electric service which requires the construction of an extension to the Overhead System will be granted under the following conditions;
- (a) Standard Allowance - For each residence, the Company will construct single-phase distribution line extensions at its own cost a distance of 600 feet, of which no more than 250 feet will be on private property (lateral extension).

If the distribution line is constructed such that it can be available to serve only two premises (joint lot line construction), such extension shall be considered as a lateral extension, and the customer(s) requesting service shall each be granted up to 250 feet of free footage. For purposes of this policy, secondary voltage distribution lines shall not be considered as a line extension.

(Continued on Sheet No. C-28.00)

Issued _____, 2025

M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

**See Bennett Direct Testimony Page
51 Line 1 through Line 12**

Effective for service rendered on
and after _____, 2025

Issued under authority of the
Michigan Public Service Commission
dated _____, 2025
in Case No. U-21534

(Continued from Sheet No. C-27.00)

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

C6.2 Overhead Extension Policy (Contd.)

- (b) Charges - Single phase overhead line extensions in excess of the above footage will require a refundable construction advance of ~~\$6.50~~ **16.91** per foot, measured from pole to pole, plus a non-refundable contribution for the estimated line clearance cost for such excess footage. There may also be a non-refundable contribution in aid of construction equal to the cost of securing right of way. Three-phase extensions will be on the same basis as Commercial and Industrial.
- (c) Measurement - The length of any extension will be measured along the route of the extension from the Company's nearest facilities from which the extension can be made to the point of connection with the service drop.

Should the Company for its own reasons choose a longer route, the applicant will not be charged for the additional distance, however, if the customer requests special routing of the line, the customer will be required to pay a non-refundable contribution in aid of construction for the extra cost resulting from the special routing.

- (d) Refunds - During the five (5) year period immediately following the date the line extension is completed, the Company will make refunds of the refundable construction advance paid for a financed extension under provisions of Paragraph (2) above. The amount of any such refund shall be equal to two (2) times the estimated average annual revenue or \$500 (whichever is greater) for each additional standard allowance customer subsequently connected directly to the facilities financed by the original customer. Directly connected residential customers are those which do not require the construction of more than 600 ft. of single phase line extension or 250 feet on private property. Directly connected commercial or industrial customers are those which do not require payment of a refundable construction advance. Such refunds will be made only to the original customer and will not include any amount of non-refundable contribution in aid of construction for underground service made under the provisions of the Company's underground service policy. The refund shall not exceed the total refundable construction advance. The refundable construction advance shall not bear interest.
- (2) Underground Extension Policy - The Company will 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 property where transition from overhead to underground can be made.

(Continued on Sheet No. C-29.00)

Issued _____, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

**See Hill Direct Testimony Page 30
Line 1 through Page 31 Line 1**

Effective for service rendered on
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Michigan Public Service Commission
dated _____, 2025
in Case No. U-21534

(Continued from Sheet No. C-29.00)

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

C6.2 Overhead Extension Policy (Contd.)

The amount of any such refund shall be equal to two (2) times the actual annual revenue or \$500 (whichever is greater) for each standard allowance customer subsequently connected directly to the facilities financed by the original customer. Directly connected residential customers are those which do not require the construction of more than 600 feet of single phase line extension or 250 feet on private property. Directly connected commercial and industrial customers are those which do not require payment of a refundable construction advance. Refunds will not be made until the original customer(s) estimated revenues are exceeded by actual revenues as a result of the line extension.

(4) Commercial and Industrial Customers - 1,000 kW and larger

- (a) Standard Allowance - Except for non-refundable contribution in aid of construction for underground service made under the provisions of Rules C6.3 and C6.4, and reserving the Company's rights under C6.1(7), the Company will finance the construction cost necessary to extend its facilities to serve commercial or industrial customers 1,000 kW and larger when such investment does not exceed the allowance calculated using the Standard Allowance Table below. The Company may require the customer to contract for a minimum demand or minimum bill as a condition for providing the allowance.

Standard Allowance –Commercial and Industrial Customers 1,000 kW and Larger*

Rate Schedule	Full Service Contract Term, Years					No Full Service Contract
	1	2	3	4	5	
D11, D10, D3	~~\$115~~ -125 / kW	~~\$220~~ -240 / kW	~~\$325~~ -345 / kW	~~\$420~~ -450 / kW	~~\$505~~ -540 / kW	~~\$1430~~ / kW
D6.2	\$120 / kW	\$230 / kW	\$330 / kW	\$430 / kW	\$520 / kW	~~\$130~~ -140 / kW
D8, R1.1, R1.2, D3.3	~~\$90~~ -100 / kW	~~\$175~~ 190 / kW	~~\$274~~ 5 / kW	~~\$320~~ -355 / kW	~~\$385~~ 430 / kW	~~\$130~~ -140 / kW
R10	~~\$120~~ / kW	~~\$40~~ -15 / kW	~~\$85~~ 20 / kW	~~\$110~~ -25 / kW	~~\$135~~ -30 / kW	~~\$130~~ -140 / kW
D4	~~\$240~~ -275 / kW	~~\$460~~ -530 / kW	~~\$76~~ 70 / kW	~~\$865~~ kW 990kW	~~\$1,050~~ 1,200 / kW	~~\$1430~~ / kW

*Allowances are based on the anticipated average Maximum Demand in kW during the contract term.

(Continued on Sheet No. C-31.00)

Issued _____, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

See Willis Direct Testimony Page
45 Line 12 through Line 20

Effective for service rendered on
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Michigan Public Service Commission
dated _____, 2025
in Case No. U-21534

(Continued from Sheet No. C-33.00)

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

C6.3 Underground Distribution Systems (Contd.)

B Distribution for Residential Subdivisions

(1) General

- (a) Distribution facilities in all new residential subdivisions and existing residential subdivisions in which electric distribution facilities have not already been constructed shall be placed underground, except that a lot 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.
- (b) The Company will install an underground distribution system, including primary and secondary cable and all associated equipment, to provide service to the lot line of each lot in the subdivision.
- (c) For purposes of definition, all one-family and two-family buildings on individual lots are residential.
- (d) The developer of a new residential subdivision shall cause to be recorded with the plat of the subdivision a public utility easement approved by the Company for the entire plat. Such easement shall include a legal description of areas within the plat which are dedicated for utility purposes and also other restrictions as shall be determined by the Company for construction, operation, maintenance and protection of its facilities.
- (e) Where sewer lines will parallel Company cables, taps must be extended into each lot for a distance of one (1) foot beyond the easement prior to installation of the cables.

(2) Charges - Prior to commencement of construction, the owner or developer will pay to the Company an amount equal to the estimated cost of construction of the distribution system, but not less than the non-refundable contribution in aid of construction determined by multiplying the sum of the lot front footage for all lots in the subdivision by ~~\$3.00~~ 18.30, except for those lots served by an underground service from an overhead distribution line as previously stated in this rule.

(3) Refunds - The balance of the charges (refundable construction advance) shall be made available to the developer or owner on the following basis:

During the five (5) year period immediately following completion of the distribution construction, the Company will refund two (2) times the estimated average annual revenue or \$500 (whichever is greater) for each permanent residential customer connected within the subdivision. Such refunds will be made only to the original developer or owner and in total shall not exceed the refundable construction advance. The refundable construction advance shall bear no interest.

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

C6.3 Underground Distribution Systems (Contd.)

- (4) Measurement - The front foot measurement of each lot to be served by a residential underground distribution system will be made along the contour of the front lot line. The front lot line is that line which usually borders on or is adjacent to a street. However, when streets border on more than one side of a lot, the shortest dimension will be used. In case of a curved lot line which borders on a street or streets and represents at least two sides of the lot, the front foot measurement will be considered as one-half the total measurement of the curved lot line. The use of the lot front foot measurement in these rules shall not be construed to require that the underground electric distribution facilities be placed at the front of the lot.
- (5) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.
- (6) Extension of Existing Distribution Systems in Platted Subdivisions - Any such extension shall be considered a distinct, separate unit, and any subsequent extensions therefrom shall be treated separately.
- (a) Charge - Prior to commencement of construction the applicant shall make a non-refundable contribution in aid of construction in an amount equal to ~~\$3.00~~18.30 per lot front foot for the total front footage of all lots which can be directly served in the future from the distribution system installed to serve the initial applicant. All subsequent applicant(s) for service on these lots shall be required to make a non-refundable contribution in aid of construction in the amount of ~~\$3.00~~18.30 per lot front foot for all lots owned by the subsequent applicant(s) which can be directly served from the original distribution extension.
- (b) Refunds - The Company will refund to the original applicant the amounts contributed in aid of construction by subsequent applicants as provided in Paragraph 1 above. The total amount refunded shall not exceed the amount of the original contribution, and will be made only to the original applicant. The Company will endeavor to maintain records for such purposes but the original applicant is ultimately responsible to duly notify the Company of refunds due; any refund not claimed within five (5) years after the date of completion of distribution constructions shall be forfeited. Refunds made under the provisions of this paragraph shall be in addition to refunds made under the Company's overhead line extension policy.
- (c) Measurements - The lot front footage used in computing charges and contributions in Paragraph 1 above shall be measured the same as for new subdivisions.
- (d) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

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

C6.3 Underground Distribution Systems (Contd.)

C Distribution for Mobile Home Parks

(1) General

- (a) For purposes of this rule, the definition of a mobile home park is a parcel or tract of land under the control of a person(s) upon which three or more mobile homes are located on a continual non-recreational basis not intended for use as a temporary trailer park.
- (b) Distribution facilities in new mobile home parks shall be placed underground. Extension from existing overhead systems in mobile home parks will be placed underground at the option of the park owner.
- (c) This service is limited to mobile home parks in which the service is metered by the Company at secondary voltage.
- (d) Company cables shall be separated by at least five feet from paralleling underground facilities which do not share the same trench. The park owner's cable systems, such as community antenna systems, should be in separate trenches, if possible. Subject to an agreement with the Company these cable systems may occupy the same trench. The park owner must agree to pay a share of the trenching cost plus the extra cost of the additional backfill, if required, and agree to notify the other using utilities when maintenance of his cable requires digging in the easement.
- (e) The park owner must provide for each mobile home lot a meter pedestal of a design acceptable to the Company.

(2) Charges - The park owner shall be required to make a non-refundable contribution in aid of construction as follows:

- (a) Prior to commencement of construction, the owner or developer will pay to the Company an amount equal to the estimated cost of construction of the distribution system, but not less than the non-refundable contribution in aid of construction determined by multiplying the sum of the lot front footage for all lots in the park by ~~\$3.00~~18.30, except for those lots served by an underground service from an overhead distribution line as previously stated in this rule.
- (b) Service Loops or Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.
- (c) Transformers - ~~\$7.50~~18.47 per kVA, for the total nameplate kVA installed.

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

C6.3 Underground Distribution Systems (Contd.)

- (d) Measurements - The lot front footage used in computing charges and contributions shall be measured the same as for new subdivisions.

D Distribution for Condominiums and Apartment House Complexes

- (1) This service is limited to multiple occupancy buildings in which service is metered by the Company at secondary voltage. These include, but are not limited to, low-rise apartments, townhouses, condominiums and cluster housing where space is available for pad-mounted transformers and other above-grade equipment and the area is suitable for the direct burial installation of cable. Where the developer and/or the Company are concerned that the easement area could be developed with patios, etc., special facilities such as conduit may be required to allow the Company to maintain the system. If special facilities are required, the developer will be responsible for providing them.

(2) Charges

- (a) Primary and Secondary - The owner will pay to the Company, prior to construction, a non-refundable contribution in aid of construction arrived at by multiplying the total length of trench feet required for distribution facilities by ~~\$4.30~~17.84 plus ~~\$7.50~~18.47 per kVA (nameplate) of transformer capacity to be installed.
- (b) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

E Distribution for Commercial and Industrial Subdivisions

The Company will install underground facilities to serve commercial and industrial customers and other installations within designated underground districts in cooperation with the developer or owner, evidenced by a separate signed agreement, subject to the following specific conditions:

(1) General

- (a) Where overhead lines are allowed by MPSC Rules for a specific installation and are objected to by a person or municipality, the Company, where feasible, will honor a request or directive that such lines be constructed underground. The objecting party shall be responsible for the payment of the additional cost of the underground facilities.
- (b) When required, the developer or owner must provide suitable space and the necessary foundations and/or vaults for equipment and provide trenching, back-filling, conduits and manholes acceptable to the Company for installation of cables on his property.

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

C6.3 Underground Distribution Systems (Contd.)

- (c) Distribution facilities in the vicinity of new industrial loads and built solely to serve such loads will be placed underground at the option of the applicant. This includes service to all buildings used primarily for the assembly, processing or manufacturing of goods.

(2) Charges

- (a) Distribution System - For standard installation of distribution facilities, the applicant(s) shall make a non-refundable contribution in aid of construction in the amount equal to the total length in feet multiplied by ~~\$4.30~~ 17.84.
- (b) Transformers - Transformers will be charged on an installed basis of ~~\$7.50~~ 18.47 per kVA.
- (c) Service Laterals - The Company will install, own, operate and maintain an underground service lateral as defined in Section C6.4.

(3) Measurement

- (a) Trench length shall be determined by measuring along the centerline of the trench.

Primary and Secondary Extensions shall be measured along the route of the primary and secondary cable from the transition pole to each transformer or other termination. No additional charge will be made for secondary or service cable laid in the same trench with primary cable.

C6.4 Underground Service Connections

The Company will install, own, operate and maintain underground service connections in cooperation with the developer or owner, evidenced by a separate signed agreement, subject to the following charges:

A Residential Subdivisions

The applicant shall make a non-refundable contribution in aid of construction for a standard 3/0 aluminum service in the amount of ~~\$300~~ 730 for trench lengths up to 200 feet. For any additional trench length in excess of 200 feet the non-refundable contribution will be increased by ~~\$3.90~~ 9.48 per foot for each additional foot added. When required, larger services will be provided, and the additional cost will be included in the non-refundable contribution in aid of construction. The trench length is measured from the Company's electrical connection, to the customer's meter.

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

C6.4 Underground Service Connections (Contd.)

B Residential Outside Subdivisions and Mobile Home Parks

The applicant shall make a non-refundable contribution in aid of construction for a standard 3/0 aluminum service in the amount equal to the product of the trench length in feet multiplied by ~~\$3.90~~9.48. When required, larger services will be provided, and the additional cost will be included in the non-refundable contribution in aid of construction. All new, relocated or upgraded residential service connections will be installed as underground residential service laterals at the customer's expense as set forth in Section C6.4.

C Apartment House Complexes and Condominiums

The applicant shall make a non-refundable contribution in aid of construction in the amount equal to the product of the trench length in feet multiplied by ~~\$4.30~~17.84. See C1.1 for service charge differences in secondary network areas.

No charge will be made for service laterals laid in the same trench with primary or secondary cables. Residential units shall be metered separately in accordance with Standard Contract Rider No. 4.

When any component of a secondary service involves a residential load, then the main building service utilization voltage shall be the residential voltage (i.e. 240/120 volts or 208Y/120 volts).

(1) Outdoor Pad-Mounted Installation – External Residential Meter Stacks:

- (a) The Company will furnish, install, own and maintain the pre-meter portion of the individual service lateral between the distribution facilities and self-contained meter locations.
- (b) Where service laterals are installed by the Company as in (a) above, the customer will furnish and install the service lateral in a manner suitable to the Company. The Company will make connection of the customer furnished lateral to its distribution system.

(2) Outdoor Pad-Mounted Installation – Mixed Use Secondary Served Buildings:

- (a) When a commercial or industrial building is divided in such a manner as to require several self-contained meter locations (as described above), the owner shall be required to make provisions for a common pre-meter feed either by grouping meters in a manner and location acceptable to the Company, or by installing a Company approved secondary connection cabinet at a Company approved location. The owner shall install one (1) 4" conduit for every 400 amps or part thereof of capacity, based on the rating of the secondary connection cabinet, plus one (1) additional 4" conduit

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

C6.4 Underground Service Connections (Contd.)

- (c) the tenant meter location. The meters must be grouped and installed in a manner acceptable to the Company. Residential meters must be installed in the same room as the dry-type transformers feeding them. The load at each transformer location must be sufficient to justify the use of one standard Company transformer or multiples thereof. Standard Company transformer sizes and secondary voltages for this application are: 167 kVA single phase 120/240 V and 300 kVA three-phase 208Y/120 V. Fuse cabinets and associated equipment will be furnished, owned and maintained by the Company at each transformer location. The fuse cabinets and associated equipment will be paid for and installed by the customer. The transformer locations must be suitable for the installation of dry type transformers and must be accessible for operation and maintenance. The installations must be approved by the Company and must meet code requirements. Suitable access and means shall be provided for transformer, fuse cabinet and associated equipment replacement. The customer shall be responsible for all damages and personal liability arising out of or in connection with the installation of the Company's transformers, fuse cabinets and associated equipment and shall also take reasonable steps to prevent damage to the transformers, fuse cabinets and associated equipment when they are installed on his property.

The owner will pay the following charges to the Company:

- (a) ~~\$4.30~~ \$17.84 per trench foot of cable on private property between the primary switching equipment and the property lines nearest the point of connection to the Company distribution system-plus any other Company charges for unusual conditions.
- (b) The installed cost of the primary switchgear.
- (c) \$15 per kVA for all dry type transformers.
- (d) The delivered cost of the fuse cabinet and associated equipment.
- (e) The developer or owner must provide suitable space and necessary foundations for pad-mounted transformer and the primary switchgear, etc., and he must provide for any trenching, conduit, or manholes acceptable to the Company.

(4) Measurement:

Service laterals shall be measured from the pole or underground secondary terminal to which the service lateral is connected along the route of the lateral trench or conduit to the point of connection to the customer's facilities. No charge will be made for service laterals laid in the same trench with primary or secondary cables.

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C8 SURCHARGES AND CREDITS APPLICABLE TO POWER SUPPLY SERVICE

C8.1 Power Supply Cost Recovery (PSCR) Clause

- A This Power Supply Cost Recovery Clause permits the monthly adjustment of rates for power supply to allow recovery of the booked costs of fuel and purchased and net interchanged power transactions incurred under reasonable and prudent policies and practices in accordance with 1982 PA 304. All rates for electric service, unless otherwise provided in the applicable rate schedule, shall include a Power Supply Cost Recovery factor.
- B The Power Supply Cost Recovery factor is that element of the rates to be charged for electric service to reflect power supply costs incurred by the company and made pursuant to the Power Supply Cost Recovery Clause.
- C Effective _____, ~~2025~~~~December 15, 2023~~ the Power Supply Cost Recovery Factor shall consist of an increase or decrease of 0.010769~~0.010746~~ mills per kWh for each full .01 mill increase or decrease in the projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a base of 31.26 mills per kWh. Average booked cost 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. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

The following factor(s) were applied to bills rendered during the billing months as indicated below for the calendar years 2023 and 2024.

	2023		2024	
	<u>Maximum</u> <u>Authorized</u> <u>Factor</u>	<u>Actual</u> <u>Factor</u> <u>Billed</u>	<u>Maximum</u> <u>Authorized</u> <u>Factor</u>	<u>Actual</u> <u>Factor</u> <u>Billed</u>
<u>Billing Month</u>	<u>¢/kWh</u>	<u>¢/kWh</u>	<u>¢/kWh</u>	<u>¢/kWh</u>
January	1.917	0.665	1.127	1.127
February	1.917	0.665	1.127	1.127
March	1.917	1.750	1.127	1.127
April	1.917	1.750		
May	1.917	1.750		
June	1.917	1.917		
July	1.917	1.917		
August	1.917	1.917		
September	1.917	1.917		
October	1.917	1.917		
November	1.917	1.917		
December	1.917	1.127		

The Company will file a revised Sheet No. C-62.00 monthly, or as necessary, to reflect the factor to be billed the following month.

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C8 SURCHARGES AND CREDITS APPLICABLE TO POWER SUPPLY SERVICE (Contd.)

C8.5 SURCHARGES AND CREDITS APPLICABLE TO POWER SUPPLY SERVICE: Summary of surcharges and credits including PSCR, pursuant to [sub-rules C8.1](#), C8.4 of this rule. (Cents per kilowatthour or percent of base bill unless otherwise noted).

	PSCR (¢/kWh)	Securitization Charge <i>River Rouge</i> (¢/kWh)	Securitization Charge TCSC (¢/kWh)	Total Power Supply Surcharges (excludes REPS) (¢/kWh)
Residential				
D1 Non Transmitting Meter	1.127	0.0240	0.2889	1.4399
D1.1 Int. Space Conditioning	1.127	0.0190	0.2285	1.3745
D1.2 Enhanced TOU	1.127	0.0156	0.1873	1.3299
D1.6 Special Low Income Pilot	1.127	0.0240	0.2889	1.4399
D1.7 Geothermal Time-of-Day	1.127	0.0142	0.1705	1.3117
D1.8 Dynamic Peak Pricing	1.127	0.0207	0.2493	1.3970
D1.9 Electric Vehicle	1.127	0.0182	0.2195	1.3647
D1.11 Standard TOU	1.127	0.0240	0.2889	1.4399
D1.13 Overnight Savers	1.127	0.0240	0.2889	1.4399
D2 Space Heating	1.127	0.0145	0.1751	1.3166
D5 Water Heating	1.127	0.0128	0.1540	1.2938
D9 Outdoor Lighting	1.127	0.0047	0.0563	1.1880
Commercial				
D1.1 Int. Space Conditioning	1.127	0.0165	0.1981	1.3416
D1.7 Geothermal Time-of-Day	1.127	0.0109	0.1316	1.2695
D1.8 Dynamic Peak Pricing	1.127	0.0171	0.2062	1.3503
D1.9 Electric Vehicle	1.127	0.0242	0.2917	1.4429
D3 General Service	1.127	0.0191	0.2303	1.3764
D3.1 Unmetered	1.127	0.0159	0.1918	1.3347
D3.2 Educ. Inst.	1.127	0.0166	0.1995	1.3431
D3.3 Interruptible	1.127	0.0160	0.1924	1.3354
D3.5 Charging	1.127	0.0191	0.2303	1.3764
<u>D3.11 TOU General Service</u>	<u>1.127</u>	<u>0.0191</u>	<u>0.2303</u>	<u>1.3764</u>
D4 Large General Service	1.127	0.0168	0.2026	1.3464
D5 Water Heating	1.127	0.0113	0.1356	1.2739
D9 Outdoor Lighting	1.127	0.0047	0.0563	1.1880
R3 Standby (Secondary)	1.127	0.0131	0.1579	1.2980
R7 Greenhouse Lighting	1.127	0.0109	0.1316	1.2695
R8 Space Conditioning	1.127	0.0167	0.2014	1.3451
Industrial				
D6.2 Educ. Inst.	1.127	0.0173	0.2081	1.3524
D8 Interruptible Primary	1.127	0.0099	0.1189	1.2558
D10 Schools	1.127	0.0169	0.2029	1.3468
D11 Primary Supply	1.127	0.0136	0.1635	1.3041
D12 Large Low Peak	1.127	0.0136	0.1635	1.3041
D13 XL	NA	0.0022	0.0262	0.0284
<u>D14 TOU Primary Supply</u>	<u>1.127</u>	<u>0.0136</u>	<u>0.1635</u>	<u>1.3041</u>
R1.1 Metal Melting	1.127	0.0102	0.1083	1.2455
R1.2 Electric Process Heating	1.127	0.0087	0.1061	1.2418
R3 Standby (Primary)	1.127	0.0131	0.1579	1.2980
R10 Interruptible Supply	NA	0.0022	0.0262	0.0284
Governmental				
E1 Streetlighting	1.127	0.0046	0.0555	1.1871
E1.1 Energy Only	1.127	0.0132	0.1591	1.2993
E2 Traffic Lights	1.127	0.0125	0.1499	1.2894

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C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE

C9.1 Nuclear Surcharge (NS)

On January 1987 MPSC Order authorized the establishment of an external trust fund to finance the decommissioning of Fermi 2 Power Plant when its operating license expires. The Order approves a decommissioning surcharge on customer bills under which the funds are collected. Pursuant to Commission Order U-10102 dated January 21, 1994, a revised surcharge became effective with service rendered on and after January 22, 1994. In the same order, the Commission authorized the establishment of an external fund to finance the disposal of low-level radioactive waste during the operating life of Fermi 2 Power Plant. Pursuant to an order in Case No. U-14399, costs associated with site security and radiation protection services were removed from base rates and transferred to the Nuclear Surcharge. Pursuant to Commission Order U-16472 dated October 20, 2011, a revised surcharge became effective with service rendered on and after October 29, 2011 Pursuant to Commission Order in Case No. U-17767 a revised surcharge became effective with service rendered on and after December 17, 2015. Pursuant to Commission Order in Case No. U-18255 a revised surcharge became effective with service rendered on and after April 18, 2018. Pursuant to Commission Order in Case No. U-20162 a revised surcharge became effective with service rendered on and after May 9, 2019. Pursuant to Commission Order in Case No. U-20561 a revised surcharge became effective with service rendered on and after May 15, 2020. Pursuant to Commission Order in Case No. U-20836 a revised surcharge became effective with service rendered on and after November 25 ,2022. Pursuant to Commission Order in Case No. U-21297 a revised surcharge became effective with service rendered on and after December 15 ,2023. Pursuant to Commission Order in Case No. U-21534 a revised surcharge became effective with service rendered on and after _____, 2025.

C9.2 HOLD FOR FUTURE USE

C9.3 HOLD FOR FUTURE USE

C9.4 HOLD FOR FUTURE USE

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C9.7.11 INVESTMENT RECOVERY MECHANISM

On December 15, 2023, the Michigan Public Service Commission approved the Investment Recovery Mechanism (IRM) in Case No. U-21297. The IRM recovers costs related to certain distribution system investments. A schedule of IRM surcharges ~~covering two IRM years was~~ approved by the Commission ~~and~~ is reflected below. The IRM surcharge is applied on the same basis as the underlying rate schedule. The surcharge schedule ~~is will be~~ updated consistent with ~~subsequent~~ the _____, 2025 Commission Orders ~~in Case No. U-21534~~.

	13mos Ending December 31, 2024	Year Ending December 31, 2025	Year Ending December 31, 2026	Year Ending December 31, 2027
<u>All residential</u> , except as noted below (¢/kWh)	0.0139	0.0941	<u>0.3227</u>	<u>0.6902</u>
<u>Commercial</u>				
All commercial, except as noted below (¢/Kwh)	0.0088	0.0595	<u>0.2058</u>	<u>0.4402</u>
Rate Schedule D4 (\$/kW)	0.0362	0.2454	<u>0.8881</u>	<u>1.8998</u>
<u>Industrial</u>				
Primary, except as noted below (\$/kW)	0.0107	0.0727	<u>0.2375</u>	<u>0.5080</u>
Subtransmission, except as noted below (\$/kW)	0.0046	0.0312	<u>0.0889</u>	<u>0.1901</u>
Transmission, except as noted below (\$/kW)	0.0000	0.0000	<u>0.0000</u>	<u>0.0000</u>
Rate Schedule D10 (¢/Kwh)	0.0034	0.0233	<u>0.0703</u>	<u>0.1504</u>
Rider 1.1 / 1.2 (Distribution Voltage) (¢/Kwh)	0.0082	0.0555	<u>0.2058</u>	<u>0.4402</u>
Rider 1.1 / 1.2 (Primary Voltage) (¢/Kwh)	0.0034	0.0229	<u>0.0707</u>	<u>0.1512</u>
Rider 1.1 / 1.2 (Subtransmission Voltage) (¢/Kwh)	0.0015	0.0104	<u>0.0249</u>	<u>0.0532</u>
Rider 1.1 / 1.2 (Transmission Voltage) (¢/Kwh)	0.0000	0.0000	<u>0.0000</u>	<u>0.0000</u>
D13 (Primary Voltage) (¢/Kwh)	0.0020	0.0133	<u>0.0434</u>	<u>0.0928</u>
D13 (Subtransmission Voltage) (¢/Kwh)	0.0008	0.0057	<u>0.0162</u>	<u>0.0347</u>
D13 (Transmission Voltage) (¢/Kwh)	0.0000	0.0000	<u>0.0000</u>	<u>0.0000</u>
<u>Other</u>				
D9 OPL (Residential) (¢/Kwh)	0.0778	0.5352	<u>1.8962</u>	<u>4.0561</u>
D9 OPL (Commercial) (¢/Kwh)	0.0434	0.2988	<u>0.9737</u>	<u>2.0828</u>
E1 St Light (¢/Kwh)	0.0819	0.5140	<u>1.7401</u>	<u>3.7222</u>
E2 Signals (¢/Kwh)	0.0040	0.0275	<u>0.0954</u>	<u>0.2041</u>

C9.7.11 HOLD FOR FUTURE USE

C9.7.12 HOLD FOR FUTURE USE

C9.7.13 HOLD FOR FUTURE USE

(Continued on Sheet No. C-69.03)

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C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

C9.8 Summary of Surcharges and Credits: Summary of surcharges and credits, pursuant to sub-rules C9.1, C9.2, C9.6, C9.7.9, and C.9.7.14. Cents per kilowatthour or percent of base bill, unless otherwise noted.

	<u>NS</u> ¢/kWh	<u>EWRS</u> ¢/kWh	<u>Base</u> <u>Securitization</u> ¢/kWh	<u>IRM</u> ¢/kWh	<u>Total Delivery</u> <u>Surcharges</u> ¢/kWh	<u>LIEAF Factor</u> <u>\$/Billing</u> <u>Meter</u>
Residential						
D1 Non Transmitting Meter	<u>0.0911</u> ~~0.0882~~	0.2552	0.1630	0.0139	<u>0.5232</u> ~~0.6670~~	\$0.88
D1.1 Int. Space Conditioning	<u>0.0911</u> ~~0.0882~~	0.2552	0.1514	0.0139	<u>0.5116</u> ~~0.6554~~	N/A
D1.2 Enhanced TOU	<u>0.0911</u> ~~0.0882~~	0.2552	0.1493	0.0139	<u>0.5095</u> ~~0.6533~~	\$0.88
D1.6 Special Low Income Pilot	<u>0.0911</u> ~~0.0882~~	0.2552	0.1630	0.0139	<u>0.5232</u> ~~0.6670~~	\$0.88
D1.7 Geothermal Time-of-Day	<u>0.0911</u> ~~0.0882~~	0.2552	0.1411	0.0139	<u>0.5013</u> ~~0.6451~~	N/A
D1.8 Dynamic Peak Pricing	<u>0.0911</u> ~~0.0882~~	0.2552	0.1628	0.0139	<u>0.5230</u> ~~0.6668~~	\$0.88
D1.9 Electric Vehicle	<u>0.0911</u> ~~0.0882~~	0.2552	0.1595	0.0139	<u>0.5197</u> ~~0.6635~~	N/A
D1.11 Standard TOU	<u>0.0911</u> ~~0.0882~~	0.2552	0.1630	0.0139	<u>0.5232</u> ~~0.6670~~	\$0.88
D1.13 Overnight Savers	<u>0.0911</u> ~~0.0882~~	0.2552	0.1630	0.0139	<u>0.5232</u> ~~0.6670~~	\$0.88
D2 Space Heating	<u>0.0911</u> ~~0.0882~~	0.2552	0.1583	0.0139	<u>0.5185</u> ~~0.6623~~	\$0.88
D5 Wtr Htg	<u>0.0911</u> ~~0.0882~~	0.2552	0.1561	0.0139	<u>0.5163</u> ~~0.6601~~	N/A
D9 Outdoor Lighting	<u>0.0911</u> ~~0.0882~~	0.2552	0.1371	0.0778	<u>0.5612</u> ~~0.7050~~	N/A
Commercial						
D1.1 Int. Space Conditioning	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1086	0.0088		\$0.88
D1.7 Geothermal Time-of- day	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0734	0.0088		\$0.88
D1.8 Dynamic Peak Pricing	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0908	0.0088		\$0.88
D1.9 Electric Vehicle	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1920	0.0088		\$0.88
D3 General Service	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0999	0.0088		\$0.88
D3.1 Unmetered	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0939	0.0088		N/A
D3.2 Educ. Inst.	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0877	0.0088		\$0.88
D3.3 Interruptible	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0899	0.0088		\$0.88
D3.5 Charging	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0999	0.0088		\$0.88
D3.11 TOU General Service	<u>0.0911</u>	See C9.6	0.0999	0.0088		\$0.88
D4 Large General Service	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1044	See C9.7.11		\$0.88
D5 Wtr Htg	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0988	0.0088		\$0.88
D9 Outdoor Lighting	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1371	0.0434		N/A
R3 Standby Secondary	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0140	0.0088		\$0.88
R7 Greenhouse Lighting	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0896	0.0088		\$0.88
R8 Space Conditioning	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0977	0.0088		\$0.88
Industrial						
D6.2 Educ. Inst.	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0167	See C9.7.11		\$0.88
D8 Interruptible Primary	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0096	See C9.7.11		\$0.88
D10 Schools	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0230	See C9.7.11		\$0.88
D11 Primary Supply	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0082	See C9.7.11		\$0.88
D12 Large Low Peak	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0082	See C9.7.11		\$0.88
D13 XL	N/A	See C9.6	0.0033	See C9.7.11		\$0.88
D14 TOU Primary Supply	<u>0.0911</u>	See C9.6	0.0082	See C9.7.11		\$0.88
R1.1 Metal Melting	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0099	See C9.7.11		\$0.88
R1.2 Electric Process Heating	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0157	See C9.7.11		\$0.88
R3 Standby Primary	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0140	See C9.7.11		\$0.88
R10 Interruptible Supply	<u>0.0911</u> ~~0.0882~~	See C9.6	0.0033	See C9.7.11		\$0.88

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C9 SURCHARGES AND CREDITS APPLICABLE TO DELIVERY SERVICE: (Contd.)

C9.8 Summary of Surcharges and Credits (Contd.):

	<u>NS</u> ¢/kWh	<u>EWRS</u> ¢/kWh	<u>TRM</u> ¢/kWh	<u>Base</u> <u>Securitization</u> ¢/kWh	<u>IRM</u> ¢/kWh	<u>Total Delivery</u> <u>Surcharges</u> ¢/kWh	<u>LIEAF Factor</u> <u>\$/Billing</u> <u>Meter</u>
Governmental							
E1 Streetlighting Option I	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	0.1882	0.0819		N/A
E1 Streetlighting Option II & III	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	0.1882	0.0819		N/A
E1.1 Energy Only	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	0.0922	0.0088		\$0.88
E2 Traffic Lights	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	0.0407	0.0040		N/A
Electric Choice							
EC2 Residential	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	Note 1	0.0139		\$0.88
EC2 Commercial	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	Note 1	See C9.7.11		\$0.88
EC2 Primary	<u>0.0911</u> ~~0.0882~~	See C9.6	0.1467	Note 1	See C9.7.11		\$0.88

NOTE 1: Electric choice tariffs will be billed ~~the Base Securitization and IRM~~ surcharges and credits applicable to delivery service for the corresponding full service tariff, unless otherwise noted.

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RATE SCHEDULE NO. D1

RESIDENTIAL SERVICE RATE – NON-TRANSMITTING METER

AVAILABILITY OF SERVICE: Available to customers desiring service for all residential purposes through one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter.

This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications. ~~After the implementation of Rate Schedule D1.11 (Residential Service Rate – Standard TOU),~~ this rate is only available for residential customers with a non-transmitting meter.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges: ~~2.9321.128~~¢ per kWh for the first 17 kWh per day
~~4.2271.626~~¢ per kWh for excess over 17 kWh per day

Non-Capacity Energy Charge: ~~6.2377.809~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: ~~9.4518.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE:

Capacity Energy Charges: ~~2.9321.128~~¢ per kWh for the first 17 kWh per day
~~4.2271.626~~¢ per kWh for excess over 17 kWh

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: ~~9.4518.137~~¢ per kWh for all kWh

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RATE SCHEDULE NO. D1 (Contd.) RESIDENTIAL SERVICE RATE – NON-TRANSMITTING METER

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: \$(8.50) per customer per month

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision

Delivery Charges: The Special Low Income Assistance Credit is \$(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers.

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RATE SCHEDULE NO. D1 (Contd.) RESIDENTIAL SERVICE RATE – NON-TRANSMITTING METER

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a 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 Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is \$(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) **or the Special Low Income Assistance Credit (LIA).**

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~~RATE SCHEDULE NO. D1-A ————— RESIDENTIAL ADVANCED PRICING PILOT A; TIME OF USE I~~

~~**AVAILABILITY OF SERVICE:** This rate will be offered to 65,000 Company selected residential customers currently taking service on Rate Schedule D1 on an “opt in” basis. Customers who are offered this rate in this manner will be able to choose whether or not to take service pursuant to this Rate Schedule. The number of customers on this rate schedule shall be limited to the first 2,500 customers who affirmatively choose to opt in, after which additional customers shall be allowed to participate at the Company’s discretion. Any customer declining service under this rate or choosing to terminate service under this rate may not reestablish service under this rate.~~

~~————— This rate will also be offered to an additional 5,000 Company selected residential customers currently taking service on Rate Schedule D1 on an “opt out” basis. Customers who are offered this rate in this manner will receive notice from Company that they have been selected to be on this rate 60 days prior to being switched to this rate. Customers will be informed that if they do not want to take service pursuant to this rate they can inform the Company of this at any time and they will not be placed on this rate. Any Customer choosing to take service pursuant this rate may at any time in the future inform the Company they would like to discontinue service under this rate and revert to their previous rate. Any customer declining service under this rate or choosing to terminate service under rate may not reestablish service under this rate.~~

~~**HOURS OF SERVICE:** 24 hours.~~

~~**CURRENT, PHASE AND VOLTAGE:** Alternating current, single phase, nominally at 120/240 volts, three wire.~~

~~**RATE PER MONTH:**~~

~~**Full Service Customers:**~~

~~————— **Power Supply Charges:**~~

~~————— Capacity Energy Charge: 4.838 cents per kWh for all kWh~~

~~————— Non Capacity Energy Charge (June through September):~~

~~————— 5.304¢ per kWh for all On peak kWh~~

~~————— 3.612¢ per kWh for all Off peak kWh~~

~~————— Non capacity Energy Charge (October through May):~~

~~————— 4.029¢ per kWh for all On peak kWh~~

~~————— 3.612¢ per kWh for all Off peak kWh~~

~~————— On Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.~~

~~————— Off Peak Hours: All other kWh used.~~

~~————— **Delivery Charges:**~~

~~————— Service Charge: \$8.50 per month~~

~~————— Distribution Charge: 6.357¢ per kWh for all kWh~~

~~————— **Surcharges and Credits:** As approved by the Commission. See Sections C8.5 and C9.8.~~

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~~RATE SCHEDULE NO. D1-A (Contd.)—RESIDENTIAL ADVANCED PRICING PILOT A; TIME OF USE I~~

~~LATE PAYMENT CHARGE:~~ See Section C4.8.

~~MINIMUM CHARGE:~~ The Service Charge plus any applicable per meter per month surcharges.

~~CONTRACT TERM:~~ Customers shall contract to remain on this rate for at least three billing cycles terminable on three days' notice after the initial three billing cycles by either party. If the Michigan Public Service Commission orders full implementation of any advanced rate structure for residential customers this pilot will terminate, unless it is approved by the Commission in the aforementioned order.

~~WATER HEATING SERVICE:~~ Water heating service is available on an optional basis.

~~INTERRUPTIBLE SPACE CONDITIONING PROVISION:~~ Rate D1.1 is available on an optional basis.

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~~RATE SCHEDULE NO. D1-B — RESIDENTIAL ADVANCED PRICING PILOT B; TIME OF USE II~~

~~**AVAILABILITY OF SERVICE:** This rate will be offered to 65,000 Company selected residential customers currently taking service on Rate Schedule D1 on an “opt in” basis. Customers who are offered this rate in this manner will be able to choose whether or not to take service pursuant to this Rate Schedule. The number of customers on the “opt in” option of this rate schedule shall be limited to the first 2,500 customers who affirmatively chose to opt in, after which additional customers shall be allowed to participate at the Company’s discretion. Any customer declining service under this rate or choosing to terminate service under this rate may not reestablish service under this rate.~~

~~— This rate will also be offered to an additional 5,000 Company selected residential customers currently taking service on Rate Schedule D1 on an “opt out” basis. Customers who are offered this rate in this manner will receive notice from Company that they have been selected to be on this rate 60 days prior to being switched to this rate. Customers will be informed that if they do not want to take service pursuant to this rate they can inform the Company of this at any time and they will not be placed on this rate. Any Customer choosing to take service pursuant this rate may at any time in the future inform the Company they would like to discontinue service under this rate and revert to their previous rate. Any customer declining service under this rate or choosing to terminate service under rate may not reestablish service under this rate.~~

~~**HOURS OF SERVICE:** 24 hours.~~

~~**CURRENT, PHASE AND VOLTAGE:** Alternating current, single phase, nominally at 120/240 volts, three wire.~~

~~**RATE PER MONTH:**~~

~~**Full Service Customers:**~~

~~— **Power Supply Charges:**~~

~~—— Capacity Energy Charge (June through September):~~

~~—— 7.557¢ per kWh for all On peak kWh~~

~~—— 4.595¢ per kWh for all Off peak kWh~~

~~—— Capacity Energy Charge (October through May):~~

~~—— 5.291¢ per kWh for all On peak kWh~~

~~—— 4.595¢ per kWh for all Off peak kWh~~

~~—— Non Capacity Energy Charge (June through September):~~

~~—— 5.862¢ per kWh for all On peak kWh~~

~~—— 3.564¢ per kWh for all Off peak kWh~~

~~—— Non capacity Energy Charge (October through May):~~

~~—— 4.105¢ per kWh for all On peak kWh~~

~~—— 3.564¢ per kWh for all Off peak kWh~~

~~—— On Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.~~

~~—— Off Peak Hours: All other kWh used.~~

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~~RATE SCHEDULE NO. D1-B (Contd.) RESIDENTIAL ADVANCED PRICING PILOT B; TIME OF USE II~~

~~**Delivery Charges:**~~

~~Service Charge: \$8.50 per month~~

~~Distribution Charge: 6.357¢ per kWh for all kWh~~

~~**Surcharges and Credits:** As approved by the Commission. See Sections C8.5 and C9.8.~~

~~**LATE PAYMENT CHARGE:** See Section C4.8.~~

~~**MINIMUM CHARGE:** The Service Charge plus any applicable per meter per month surcharges.~~

~~**CONTRACT TERM:** "Opt in" customers shall contract to remain on this rate for at least three billing cycles terminable on three days' notice after the initial three billing cycles by either party. "Opt out" customers are open order, terminable on three days' notice by either party. If the Michigan Public Service Commission orders full implementation of any advanced rate structure for residential customers this pilot will terminate, unless it is approved by the Commission in the aforementioned order.~~

~~**WATER HEATING SERVICE:** Water heating service is available on an optional basis.~~

~~**INTERRUPTIBLE SPACE CONDITIONING PROVISION:** Rate D1.1 is available on an optional basis.~~

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RATE SCHEDULE NO. D1.1

INTERRUPTIBLE SPACE-CONDITIONING SERVICE RATE

AVAILABILITY OF SERVICE: Available on an optional basis to Residential and Commercial customers desiring separately metered interruptible service for central air conditioning and/or central heat pump use. Customers who have more than one heat pump and/or air-conditioning unit which serves their business or home, will not be permitted to have only a portion of their load on the rate, all units will be interrupted upon the signal from the Company. Installations must conform with the Company's specifications. This rate is not available to commercial customers being billed on a demand rate. Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.

HOURS OF SERVICE: 24 hours.

HOURS OF INTERRUPTION: Interruptions may be called for, but not limited to, system testing and evaluation, maintaining system integrity, ~~making an emergency purchase~~, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. The Company will limit interruptions to intervals of no longer than 30 minutes in any hour and no longer than 8 hours in any 24-hour period.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH: For separately metered space-conditioning service.

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge (June through October): ~~2.799~~~~1.089~~¢ per kWh for all kWh

Capacity Energy Charge (November through May): ~~0.694~~~~0.270~~¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~4.870~~~~6.085~~¢ per kWh for all kWh

Residential Delivery Charges:

Service Charge (June through October): \$1.95 per month

Distribution Charge (Year-round): ~~9.451~~~~8.137~~¢ per kWh for all kWh

Commercial Power Supply Charges:

Capacity Energy Charge (June through October): ~~2.713~~~~1.049~~¢ per kWh for all kWh

Capacity Energy Charge (November through May): ~~1.215~~~~0.470~~¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~5.025~~~~6.077~~¢ per kWh for all kWh

Commercial Delivery Charges:

Service Charge (June through October): \$1.95 per month

Distribution Charge (Year-round): ~~6.156~~~~5.288~~¢ per kWh for all kWh

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RATE SCHEDULE NO. D1.1 (Contd.) INTERRUPTIBLE SPACE-CONDITIONING SERVICE RATE

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through October): 2.799~~1.089~~¢ per kWh for all kWh

Capacity Energy Charge (November through May): 0.694~~0.270~~¢ per kWh for all kWh

Residential Delivery Charges:

Capacity Service Charge June through October): \$1.95 per month

Capacity Distribution Charge (Year-round): 9.451~~8.137~~¢ per kWh for all kWh

Commercial Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through October): 2.713~~1.049~~¢ per kWh for all kWh

Capacity Energy Charge (November through May): 1.215~~0.470~~¢ per kWh for all kWh

Commercial Delivery Charges:

Service Charge June through October): \$1.95 per month

Distribution Charge (Year-round): 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' written notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

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RATE SCHEDULE NO. D1.2

RESIDENTIAL SERVICE RATE – ENHANCED TOU

AVAILABILITY OF SERVICE: Available on an optional basis to customers who desire time of day service for their residential dwelling. Customers who select this rate must qualify for the Residential Service Rate Standard TOU D1.11.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge (June through October):

~~4.4741.690¢~~ per kWh for all On-peak kWh

~~1.5060.569¢~~ per kWh for all Off-peak kWh

Capacity Energy Charge (November through May):

~~3.7791.427¢~~ per kWh for all On-peak kWh

~~1.4470.547¢~~ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through October)

~~11.95513.949¢~~ per kWh for all On-peak kWh

~~4.0254.696¢~~ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (November through May)

~~10.09811.783¢~~ per kWh for all On-peak kWh

~~3.8674.512¢~~ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.

Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: \$8.50 per month

Distribution Charge: ~~9.4518.137¢~~ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through October):

~~4.4741.690¢~~ per kWh for all On-peak kWh

~~1.5060.569¢~~ per kWh for all Off-peak kWh

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RATE SCHEDULE NO. D1.2 (Contd.)

RESIDENTIAL SERVICE RATE – ENHANCED TOU

Retail Access Service Customers (Contd.):

Capacity Energy Charge (November through May):

~~3.779~~~~1.427~~¢ per kWh for all On-peak kWh

~~1.447~~~~0.547~~¢ per kWh for all Off-peak kWh

On-Peak Hours: all kWh used between 1100 and 1900 hours Monday through Friday.

Off-Peak Hours: all other kWh used.

Delivery Charges:

Service Charge: \$8.50 per month

Distribution Charge: ~~9.451~~~~8.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Commencing upon installation of the Time-of-Day meter, service will be provided for twelve continuous months thereafter, with termination upon mutual consent of the Company and the customer.

WATER HEATING SERVICE: Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: \$(8.50) per customer per month

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide

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RATE SCHEDULE NO. D1.2 (Contd.)

RESIDENTIAL SERVICE RATE— ENHANCED TOU

confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision

Delivery Charges: The Special Low Income Assistance Credit is \$(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers.

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a 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 Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is \$(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Special Low Income Assistance Credit (LIA).

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RATE SCHEDULE NO. D1.6

RESIDENTIAL SERVICE RATE - SPECIAL LOW INCOME PILOT

AVAILABILITY OF SERVICE: Customers who select this pilot rate must qualify for the Residential Service rate D1. To qualify for this pilot rate a customer must also provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. Service under this rate shall be limited to an annual average of 32,000 customers.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges: 2.932~~1.128~~¢ per kWh for the first 17 kWh per day
4.227~~1.626~~¢ per kWh for excess over 17 kWh per day

Non-Capacity Energy Charge: 6.237~~7.809~~¢ per kWh for all kWh per day

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: 9.451~~8.137~~¢ per kWh for all kWh
Special Low Income Discount: (\$50.00~~40.00~~) per month

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge.

Retail Access Service Customers:

Residential Power Supply Charges for Retail access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charges: 2.932~~1.128~~¢ per kWh for first 17 kWh per day
4.227~~1.626~~¢ per kWh for excess over 17 kWh per day

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RATE SCHEDULE NO. D1.6 (Contd.)RESIDENTIAL SERVICE RATE - SPECIAL LOW INCOME PILOT

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: ~~9.4518-137¢~~ per kWh for all kWh
Special Low Income Discount: (~~\$50.0040.00~~) per month

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

CONTRACT TERM: Open order, terminable on three days' notice by either party. If a customer fails to make the required payment on time for three consecutive billing periods that customer shall automatically be removed from this rate. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

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RATE SCHEDULE NO. D1.7

GEOHERMAL TIME-OF-DAY RATE

AVAILABILITY OF SERVICE: Available on an optional basis to residential customers desiring separately metered service for approved geothermal space conditioning and/or water heating. To qualify for the rate the water heater must be for sanitary purposes with the tank size, design and method of installation approved by the company. The space conditioning equipment must be permanently installed.

HOURS OF SERVICE: 24 Hours

CURRENT, PHASE AND VOLTAGE: Same as D1 and D3 Rates

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days notice after the initial 12 months by either party. Where special services are required, the term will be specified on the applicable contract rider.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

LATE PAYMENT CHARGE: See Section C4.8.

RATE PER DAY:

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge (June through September):

~~5.086~~~~4.248~~¢ per kWh for all On-peak kWh

~~1.685~~~~0.00~~¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

~~2.197~~~~1.717~~¢ per kWh for all On-peak kWh

~~1.727~~~~0.369~~¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through September)

9.310¢ per kWh for all On-peak kWh

3.084¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (November through September)

4.023¢ per kWh for all On-peak kWh

3.161¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.

Off-Peak Hours: All other kWh used.

~~Non-Capacity Energy Charge: 4.582¢ per kWh for all kWh~~

Residential Delivery Charges:

Service Charge: 6.70¢ per day

Distribution Charge: ~~9.451~~~~8.137~~¢ per kWh for all kWh

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RATE SCHEDULE NO. D1.7 (Contd.)

GEOHERMAL TIME-OF-DAY RATE

Commercial Power Supply Charges:

Capacity Energy Charge (June through September):

~~1.591~~~~0.893~~¢ per kWh for all On-peak kWh

~~1.453~~~~0.464~~¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

~~1.488~~~~0.572~~¢ per kWh for all On-peak kWh

~~1.488~~~~0.572~~¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through September)

3.586¢ per kWh for all On-peak kWh

3.276¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge (November through September)

3.354¢ per kWh for all On-peak kWh

3.354¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.

Off-Peak Hours: All other kWh used.

~~Non-Capacity energy Charge: 4.059¢ per kWh for all kWh~~

Commercial Delivery Charges:

Service Charge: 6.70¢ per day

Distribution Charge: ~~6.156~~~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through September):

~~5.086~~~~4.248~~¢ per kWh for all On-peak kWh

~~1.685~~~~0.001~~¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

~~2.197~~~~1.717~~¢ per kWh for all On-peak kWh

~~1.727~~~~0.369~~¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 1100 and 1900 hours Monday through Friday.

Off-Peak Hours: All other kWh used.

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RATE SCHEDULE NO. D1.7 (Contd.)

GEOHERMAL TIME-OF-DAY RATE

Residential Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: 9.451~~8.137~~¢ per kWh for all kWh

Commerical Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge (June through September):

1.591~~0.893~~¢ per kWh for all On-peak kWh

1.453~~0.464~~¢ per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

1.488~~0.572~~¢ per kWh for all On-peak kWh

1.488~~0.572~~¢ per kWh for all Off-peak kWh

Commercial Delivery Charges:

Service Charge: 6.70¢ per day
Distribution Charge: 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the commission. See Section C5.8.

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RATE SCHEDULE NO. D1.8

**RESIDENTIAL SERVICE RATE - DYNAMIC PEAK PRICING
GENERAL SERVICE RATE – DYNAMIC PEAK PRICING**

AVAILABILITY OF SERVICE: Available on an optional basis to full-service residential and secondary commercial and industrial customers seeking to manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. Service under this rate is limited to a residential customers and secondary commercial and industrial customers who have Advanced Metering Infrastructure installed. Service under this rate may not be combined with any other tariff, rider, or separately metered service, other than Rider 18 (if available).

The rate features three price tiers for On-Peak, Mid-Peak, and Off-Peak, as well as Critical Peak prices for days where Critical Hours are announced.

Definitions:

On-Peak Hours:	All kWh used between 3P.M. and 7P.M. Monday through Friday, excluding holidays
Mid-Peak Hours:	All kWh used between 7A.M. and 3P.M., and between 7P.M. and 11P.M., Monday through Friday excluding holidays
Off-Peak Hours:	All kWh used between 11 P.M and 7 A.M. Monday through Friday, and all weekend and holiday hours.
Critical-Peak Hours:	All kWh used during critical hours, which, when announced, will replace the full on-peak time period from 3 P.M. to 7 P.M.

HOURS OF INTERRUPTION: Critical Peak hours may be called for, but not limited to, system testing and evaluation, maintaining system integrity, ~~making an emergency purchase~~, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. The Company will limit Critical Peak pricing to no more than 56 hours per year.

NOTICE OF INTERRUPTION: Customers will be notified by up to 24 hours before, but no less than 6 hours before critical hours are expected to occur. Notification will be made by one or more of the following methods: automated telephone message, text message, e-mail, or presentment on an in-premise display unit furnished by the Company. Receipt of such notice is the responsibility of the participating customer.

Customers who qualify and sign up for this rate agree to participate in evaluation surveys and will remain anonymous on all such surveys.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volt, single-phase three-wire; or 208Y/120 volts, three-phase four wire service may be taken.

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**RATE SCHEDULE NO. D1.8 (Contd.) RESIDENTIAL SERVICE RATE - DYNAMIC PEAK PRICING RATE
GENERAL SERVICE RATE – DYNAMIC PEAK PRICING**

CHARGES:

Full Service Residential Customers:

Power Supply Charges:

Capacity Energy Charges: 6.229~~2.067~~¢ per kWh for all On-Peak kWh
3.252~~1.144~~¢ per kWh for all Mid-Peak kWh
1.678~~0.590~~¢ per kWh for all Off-Peak kWh
\$0.83298~~0.80253~~ per kWh for all kWh during Critical Peak Hours

Non-Capacity Energy Charge: 11.702~~14.747~~¢ per kWh for all On-Peak kWh
6.004~~7.635~~¢ per kWh for all Mid-Peak kWh
3.098~~3.940~~¢ per kWh for all Off-Peak kWh
\$0.11702~~0.14747~~ per kWh for all kWh during Critical Peak Hours

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: 9.451~~8.137~~¢ per kWh for all kWh

Full Service Secondary Commercial and Industrial Customers:

Power Supply Charges:

Capacity Energy Charges: 5.271~~2.062~~¢ per kWh for all On-Peak kWh
2.862~~1.119~~¢ per kWh for all Mid-Peak kWh
1.457~~0.570~~¢ per kWh for all Off-Peak kWh
\$0.82837~~0.80517~~ per kWh for all kWh during Critical Peak Hours

Non-Capacity Energy Charge: 12.163~~14.483~~¢ per kWh for all On-Peak kWh
6.505~~7.863~~¢ per kWh for all Mid-Peak kWh
3.311~~4.002~~¢ per kWh for all Off-Peak kWh
\$0.12163~~0.14483~~ per kWh for all kWh during Critical Peak Hours

Delivery Charges:

Service Charge: \$11.25 per month
Distribution Charge: 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

SCHEDULE OF HOLIDAYS: See Section C11

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days' notice after the initial 12 months by either party.

LATE PAYMENT CHARGE: See Section C4.8.

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**RATE SCHEDULE NO. D1.8 (Contd.) RESIDENTIAL SERVICE RATE - DYNAMIC PEAK PRICING RATE
GENERAL SERVICE RATE – DYNAMIC PEAK PRICING**

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision

Delivery Charges: The Special Low Income Assistance Credit is \$(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers.

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

Income Assistance Credit: \$(8.50) per customer per month

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a 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 Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is \$(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Special Low Income Assistance Credit (LIA).

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RATE SCHEDULE NO. D1.9**ELECTRIC VEHICLE RATE**

AVAILABILITY OF SERVICE: Available on an optional basis to residential and commercial customers desiring separately metered service for the sole purpose of charging licensed electric vehicles. Installations must conform to the Company's specifications. Service under this tariff is limited to 5,000 customers. Service on this rate is limited to electric vehicles that are SAE J1772 compliant, and all vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for the program.

HOURS OF SERVICE: 24 Hours

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three wire. In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified on the applicable contract rider.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

LATE PAYMENT CHARGE: See Section C4.8.

OPTION 1: TIME OF DAY PRICING

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge:

~~6.3872.470~~¢ per kWh for all On-peak kWh

~~1.5980.618~~¢ per kWh for all Off-peak kWh

Non-Capacity Energy Charge:

~~11.70014.635~~¢ per kWh for all On-peak kWh

~~2.9243.657~~¢ per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 9 am and 11 pm Monday through Friday.

Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: \$1.95 per month

Distribution Charge: ~~9.4518.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge:

~~6.3872.470~~¢ per kWh for all On-peak kWh

~~1.5980.618~~¢ per kWh for all Off-peak kWh

(Continued on Sheet No. D-14.04)

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(Continued from Sheet No. D-14.03)

RATE SCHEDULE NO. D1.9 (Contd.)

ELECTRIC VEHICLE RATE

Retail Access Service Customer (Contd.):

On-Peak Hours: All kWh used between 9 am and 11 pm Monday through Friday.
Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: \$1.95 per month
Distribution Charge: 9.45~~8.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See C8.5.

OPTION 2: MONTHLY FLAT FEE (Residential only):

Closed to new customers as of May 31, 2019. Existing customers will be moved to a new rate by December 31, 2019.

SPECIAL TERMS AND CONDITIONS:

Service under this rate must be supplied through a separately metered circuit and approved electric vehicle charging equipment. Installations must conform with the Company's specifications.

The Company is exploring additional possible metering options to be offered at the Company's discretion. This includes but is not limited to, collecting data directly from charging stations and/or utilizing technology beyond the general service meter to measure EV usage.

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RATE SCHEDULE NO. D1.11

RESIDENTIAL SERVICE RATE – STANDARD TOU

AVAILABILITY OF SERVICE: This rate will be available for service no later than May 31, 2023. Available to customers desiring service for all residential purposes though one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter.

This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge (June through September):

5.325 ~~2.060~~ cents per kWh for all On-peak kWh

3.208 ~~1.241~~ cents per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

3.755 ~~1.438~~ cents per kWh for all On-peak kWh

3.208 ~~1.241~~ cents per kWh for all Off-peak kWh

Non-Capacity Energy Charge (June through September):

9.748 ~~12.201~~ cents per kWh for all On-peak kWh

5.873 ~~7.354~~ cents per kWh for all Off-peak kWh

Non-Capacity Energy Charge (October through May):

6.875 ~~8.518~~ cents per kWh for all On-peak kWh

5.873 ~~7.354~~ cents per kWh for all Off-peak kWh

On-Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.

Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: \$8.50 per month

Distribution Charge: 9.451 ~~8.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

(Continued on Sheet No. D-14.06)

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(Continued from Sheet No. D-14.05)

RATE SCHEDULE NO. D1.11 (Contd.)

RESIDENTIAL SERVICE RATE – STANDARD TOU

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE:

Capacity Energy Charge (June through September):

5.325 ~~2.060~~ cents per kWh for all On-peak kWh

3.208 ~~1.241~~ cents per kWh for all Off-peak kWh

Capacity Energy Charge (October through May):

3.755 ~~1.438~~ cents per kWh for all On-peak kWh

3.208 ~~1.241~~ cents per kWh for all Off-peak kWh

Delivery Charges:

Service Charge: \$8.50 per month

Distribution Charge: 9.451 ~~8.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE: Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: \$(8.50) per customer per month

(Continued on Sheet No. D-14.07)

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RATE SCHEDULE NO. D1.11 (Contd.)

RESIDENTIAL SERVICE RATE – STANDARD TOU

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: *To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision*

Delivery Charges: *The Special Low Income Assistance Credit is \$(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers.*

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a 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 Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is \$(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Special Low Income Assistance Credit (LIA).

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Regulatory Affairs

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RATE SCHEDULE NO. D1.13

RESIDENTIAL SERVICE RATE – OVERNIGHT SAVERS

AVAILABILITY OF SERVICE: Available to customers desiring service for all residential purposes though one meter to a single or double occupancy dwelling unit including farm dwellings. A dwelling unit consists of a kitchen, bathroom, and heating facilities connected on a permanent basis. Service to appurtenant buildings may be taken on the same meter. This rate is not available for common areas of separately metered apartments and condominium complexes, nor to a separate meter which serves a garage, boat well or other non-dwelling applications. Service on this rate is limited to 10,000 customers. This rate will be effective no later than November 30, 2024.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

June – September – all values in cents per kWh

	Power supply capacity Charge	Power Supply Non Capacity Charge	Distribution Charge
On peak	~~5.925~~ 2.274	~~10.846~~ 13.470	~~19.036~~ 16.298
Off peak	~~3.987~~ 1.525	~~7.298~~ 9.031	~~14.277~~ 12.224
Super Off-peak	~~2.518~~ 0.982	~~4.609~~ 5.816	~~4.759~~ 4.075

October – May – all values in cents per kWh

	Power supply capacity Charge	Power Supply Non Capacity Charge	Distribution Charge
On peak	~~3.379~~ 1.298	~~6.186~~ 7.692	~~9.518~~ 8.149
Off peak	~~3.033~~ 1.176	~~5.552~~ 6.967	~~7.139~~ 6.112
Super Off-peak	~~2.518~~ 0.982	~~4.609~~ 5.816	~~4.759~~ 4.075

On-Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.
Super Off-peak: All kWh used between 1:00AM and 7:00AM
Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: see table above

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

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RATE SCHEDULE NO. D1.13 (Contd.)

RESIDENTIAL SERVICE RATE – OVERNIGHT SAVERS

Retail Access Service Customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity service for DTE

June – September – all values in cents per kWh

	Power supply capacity Charge	Distribution Charge
On peak	~~5.925~~ 2.274	~~19.036~~ 16.298
Off peak	~~3.987~~ 1.525	~~14.277~~ 12.224
Super Off-peak	~~2.518~~ 0.982	~~4.759~~ 4.075

October – May – all values in cents per kWh

	Power supply capacity Charge	Distribution Charge
On peak	~~3.379~~ 1.298	~~9.518~~ 8.149
Off peak	~~3.033~~ 1.176	~~7.139~~ 6.112
Super Off-peak	~~2.518~~ 0.982	~~4.759~~ 4.075

On-Peak Hours: All kWh used between 3:00PM and 7:00PM Monday through Friday.
Super Off-peak: All kWh used between 1:00AM and 7:00AM
Off-Peak Hours: All other kWh used.

Delivery Charges:

Service Charge: \$8.50 per month
Distribution Charge: see table above

Surcharges and Credits: As approved by the Commission. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: The customer shall contract to remain on this rate for at least 12 months terminable on three days' notice after the initial 12 months by either party, at which time the customer may take service on any other rate for which they are eligible.

WATER HEATING SERVICE: Water heating service is available on an optional basis.

INTERRUPTIBLE SPACE CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

(Continued on Sheet No. 14.10)

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RATE SCHEDULE NO. D1.13 (Contd.)

RESIDENTIAL SERVICE RATE – OVERNIGHT SAVERS

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: \$(8.50) per customer per month

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: *To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision*

Delivery Charges: *The Special Low Income Assistance Credit is \$(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers.*

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a 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 Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is \$(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Special Low Income Assistance Credit (LIA).

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RATE SCHEDULE NO. D2

RESIDENTIAL SERVICE RATE - SPACE HEATING

AVAILABILITY OF SERVICE: Available on an optional basis to customers desiring service for all residential purposes to a single or double occupancy dwelling unit including farm dwellings. All of the space heating must be total electric installed on a permanent basis and served through one meter. This rate also available to customers with add-on heat pumps and fossil fuel furnaces served on this rate prior to July 16, 1985. The design and method of installation and control of equipment as adopted to this service are subject to approval by the Company. This rate is also available to customers with electric heat assisted with a renewable heat source.

This rate is available only to dwellings being served on this rate prior to December 17, 2015.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire. Where available, and the demand justifies, three-phase four-wire, Y connected service may be had at 208Y/120 volts nominally. In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volt three-wire service may be taken.

RATE PER DAY:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charges: (June through October): ~~2.817~~~~1.059~~¢ per kWh for the first 17 kWh per day
~~4.027~~~~1.514~~¢ per kWh for over 17 kWh per day
Capacity Energy Charges: (November through May): ~~1.660~~~~0.624~~¢ per kWh for the first 20 kWh per day
~~0.649~~~~0.244~~¢ per kWh for over 20 kWh per day

Non-Capacity energy Charge: ~~5.498~~~~6.274~~¢ per kWh for all kWh

Delivery Charges:

Service Charge \$8.50 per month
Distribution Charge: (June through October): ~~9.451~~~~8.137~~¢ per kWh for all kWh
Distribution Charge: (November through May): ~~9.451~~~~8.137~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Applies only to actual consumption and not to the minimum charge

Retail Access Service customers:

Power Supply Charges for Retail Access Customers taking Utility Capacity Service from DTE:

Capacity Energy Charges: (June through October): ~~2.817~~~~1.059~~¢ per kWh for the first 17 kWh per day
~~4.027~~~~1.514~~¢ per kWh for over 17 kWh per day
Capacity Energy Charges: (November through May): ~~1.660~~~~0.624~~¢ per kWh for the first 20 kWh per day
~~0.649~~~~0.244~~¢ per kWh for over 20 kWh per day

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RATE SCHEDULE NO. D2 (Contd.)

RESIDENTIAL SERVICE RATE - SPACE HEATING

Delivery Charges:

Service Charge	\$8.50 per month
Distribution Charge: (June through October):	~~9.4518.137¢~~ per kWh for all kWh
Distribution Charge: (November through May):	~~9.4518.137¢~~ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Applies only to actual consumption and not to the minimum charge. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

BILLING FREQUENCY: Based on a nominal 30-day month. See Section C4.5.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

LATE PAYMENT CHARGE: See Section C4.8.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available on an optional basis.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

INCOME ASSISTANCE SERVICE PROVISION (RIA): When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: \$(8.50) per customer per month

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT: *To qualify for this credit a customer must provide annual evidence of receiving a Home Heating Credit (HHC) energy draft or warrant, or must provide confirmation by an authorized State or Federal agency verifying that the customer's total household income*

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RATE SCHEDULE NO. D2 (Contd.)

RESIDENTIAL SERVICE RATE - SPACE HEATING

SPECIAL LOW INCOME ASSISTANCE (LIA) CREDIT (contd.):

does not exceed 150% of the poverty level as published by the United States department of health and human services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. This credit shall be limited to an annual average of 32,000 customers. This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Senior Citizen Provision

Delivery Charges: The Special Low Income Assistance Credit is \$(50.00) per customer per month and is applicable to Full Service and Retail Open Access customers.

RESIDENTIAL SERVICE SENIOR CITIZEN PROVISION: When service is supplied to a 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 Service Senior Citizen Provision shall be applied as follows:

Delivery Charges: The Senior Citizen Credit is \$(4.25) per customer per month and is applicable to Full Service and Retail Open Access customers.

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) or the Special Low Income Assistance Credit (LIA).

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RATE SCHEDULE NO. D3**GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for any purpose. This rate is not available for service in conjunction with the Large General Service Rate except when used exclusively to serve electric vehicle service equipment. When exclusively serving electric vehicle service equipment, this rate may also be taken in conjunction with Rate Schedules D6.2, D8, D11, or D12. At the Company's option, service may be available to loads in excess of 1000 kW for situations where significant modifications to service facilities are not required to serve the excess load. The 1000 kW discretionary demand restriction does not apply to service provided to Electric Vehicle Fast-Charging Stations until June 1, 2026 for existing stations and for two years after beginning service for new stations. Effective May 27, 1981, this rate is not available to customers desiring service through one meter for residential purposes to a single or double occupancy dwelling unit.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge: 2.605~~1.010~~¢ per kWh for all kWh

Non-Capacity Energy Charge: 5.870~~7.096~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: 2.605~~1.010~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

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RATE SCHEDULE NO. D3.1

UNMETERED GENERAL SERVICE RATE

AVAILABILITY OF SERVICE: Available at the option of the Company to customers for loads that can be readily calculated and are impractical to meter.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

SERVICE CONNECTIONS: The customer is to furnish and maintain all necessary wiring and equipment, or reimburse the Company therefore. Connections are to be brought to the Company's underground or overhead lines by the customer as directed by the Company, and the final connections to the Company's line are to be made by the Company.

Conversion and/or relocation of existing facilities must be paid for by the customer, except when initiated by the Company. The detailed provisions and schedule of such charges will be quoted upon request.

RATE: Capacity charge of ~~2.2140.848¢~~ and non-capacity charge of ~~11.14611.247¢~~ both applied per month per kilowatthour of the total connected load in service for each customer. Loads operated cyclically will be prorated. This rate is based on 350 hours per month. Proration of cyclical loads will not apply when hours of operation are within 10% of base. Proration may either increase or decrease connected load.

The Company may, at its option, install meters and apply a standard metered rate schedule applicable to the service.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: \$3.00 per month.

CONTRACT TERM: Open order on a month-to-month basis.

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RATE SCHEDULE NO. D3.2

SECONDARY EDUCATIONAL INSTITUTION RATE

AVAILABILITY OF SERVICE: Available to Educational Institution (school, college, university) customer locations desiring service at secondary voltage. 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 owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge: 2.426~~0.939~~¢ per kWh for all kWh

Non-Capacity Energy Charge: 5.764~~6.937~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: 2.426~~0.939~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: 6.156~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the approved commission. See section C8.5.

LATE PAYMENT CHARGE: See Section C4.9.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

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RATE SCHEDULE NO. D3.3

INTERRUPTIBLE GENERAL SERVICE RATE

AVAILABILITY OF SERVICE: Available to no more than 300 customers desiring interruptible service in conjunction with service taken under the general service rate. Service to interruptible load may 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. Service to interruptible load may not be transferred to firm service circuits to avoid interruption. At the Company's option, in lieu of the requirement for separately metered circuits and associated interruption equipment the customer may elect to contract for a minimum firm load demand to protect product or process loads in accordance with the product protection provision of this tariff. Under this option, interval demand metering will be installed in order to monitor compliance when called to interrupt load. This rate is not available for loads that are primarily off-peak, such as outdoor lighting. Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.

HOURS OF SERVICE: 24 hours except as described below.

HOURS OF INTERRUPTION: All interruptible load served hereunder shall be subject to interruption by the Company and may include interruptions for, but not limited to, maintaining system integrity, ~~making an emergency purchase~~, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3.

TESTING PROCEDURES: In accordance with participation in an interruptible tariff, the customer agrees to comply with Company requirements regarding testing procedures. Customer shall complete and sign an interruptible responsibility letter annually by April 1st. Failure to sign and submit the interruptible responsibility letter may result in removal from this interruptible tariff. The letter designates that the customer understands their responsibility to interrupt, has an interruption plan, and has the capability to interrupt the contracted load. In addition, the Company will conduct multiple simulations each year to verify the communication system is working properly.

NOTICE OF INTERRUPTION: The customer shall be provided, whenever possible; 1) notice in advance (generally 1 hour) of probable interruption; 2) the time in which customer must fully reduce its interruptible load, and; 3) the estimated duration of the interruption. The customer shall be provided notice of the actual end time for the system integrity order.

NON-INTERRUPTION PENALTY: A customer who does not fully comply with the timing and load reduction prescribed in the Notice of Interruption shall be billed at the higher of (i) the rate of \$50 per kW applied to the highest 60-minute integrated interruptible demand (kW) or (ii) the actual damages incurred by the Company, including any MISO penalties, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not fully comply with an interruption order may be immediately reduced by the amount by which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

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RATE SCHEDULE NO. D3.3 (Contd.)

INTERRUPTIBLE GENERAL SERVICE RATE

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Energy Charge: ~~2.1760.844~~¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~4.9055.929~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: ~~6.1565.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: ~~2.1760.844~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: ~~6.1565.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

PRODUCT PROTECTION PROVISION: (Full Service Customers Only): A customer on rate D3.3 may elect to contract for a minimum load during the period of interruption to protect his product or process. This minimum load called "product protection load" shall not exceed 50% of the total contracted interruptible load and shall be charged rates equal to the General Service Rate (D3) power supply charge.

CONTRACT TERM: The contract term is one year, extending thereafter from month-to-month until terminated by mutual consent or on twelve months written notice by either party, which may be given at any time after the end of the first year. However, where special services are required or where the investment to serve is out of proportion to the revenue derived there from, the contract term will be as specified in the applicable contract rider or Extension of Service Agreement.

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RATE SCHEDULE NO. D3.5**COMPANY OWNED EV CHARGING SERVICE PILOT**

AVAILABILITY OF SERVICE: Available on an optional basis to customers for use of Company-owned electric vehicle charging equipment. The service may be offered by the Company for charging infrastructure of any kilowatt (kW) capacity at the Company's discretion. Availability shall be subject to the technical compatibility of the customer's vehicle and the charging equipment. This rate is limited to 100 individual chargers. EV charging equipment will be sited at the Company's discretion.

HOURS OF SERVICE: 24 hours

CURRENT, PHASE AND VOLTAGE: Service on this rate will be delivered at varying current, phase, and voltage subject to the technical specifications of the customer's vehicle and the EV charging equipment.

RATES: This service is offered as a volumetric charge at the market price of energy, and a single fixed charge encompassing all power supply capacity charges, delivery charges, and surcharges. The volumetric charge is consistent across EV charging equipment capacity. There is a separate fixed charge based on EV charging equipment capacity.

The relevant volumetric charge and session fee will be available to the customer before they choose to take service under this rate.

Volumetric Charges:

Non-Capacity Energy Charge (on peak): ~~8.0387.688¢~~ per kWh

Non-Capacity Energy Charge (off peak): ~~7.1556.843¢~~ per kWh

Fixed Charges:

Session Fee (< 200 kW charger) \$21 per vehicle-session

Session Fee (≥ 200kW charger) \$66 per vehicle-session

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8. Those surcharges reflected on a per meter basis in Sections C8.5 and C9.8 will be converted to a volumetric equivalent for this rate schedule using the following formula: ((meter/month rate)*12 months*count of installed chargers) / total projected sales.

METERING: Usage on this rate will be metered at the EV charging equipment

BILLING: An accepted form of payment is required to take service on this rate. Customers taking service on this rate will be billed at the time of service. The billing transaction may be managed by a third-party vendor on behalf of the Company.

LATE PAYMENT CHARGE: Payment is required at the point-of-sale

MINIMUM CHARGE: The Session Fee

CONTRACT TERM: Effective for the period of the charging session and governing the rates, metering, and billing of the service. There is no contractual relationship between the customer and Company beyond the charging session.

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RATE SCHEDULE NO. D3.11

GENERAL SERVICE TIME OF USE RATE

AVAILABILITY OF SERVICE: *Available to customers desiring service for any purpose. This rate is not available for service in conjunction with the Large General Service Rate except when used exclusively to serve electric vehicle service equipment. When exclusively serving electric vehicle service equipment, this rate may also be taken in conjunction with Rate Schedules D6.2, D8, D11, or D12. At the Company's option, service may be available to loads in excess of 1000 kW for situations where significant modifications to service facilities are not required to serve the excess load. The 1000 kW discretionary demand restriction does not apply to service provided to Electric Vehicle Fast-Charging Stations until June 1, 2026 for existing stations and for two years after beginning service for new stations. This rate is limited to 1000 customers. This rate will become effective no later than December 31, 2025.*

HOURS OF SERVICE: *24 hours.*

CURRENT, PHASE AND VOLTAGE: *Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.*

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

<u>Capacity Energy</u>	<u>(June – September)</u>
Summer On Peak	4.098¢ per kWh for all kWh
Summer Off Peak	2.444¢ per kWh for all kWh
<u>Capacity Energy</u>	<u>(October – May)</u>
Non-Summer On Peak	2.615¢ per kWh for all kWh
Non-Summer Off Peak	2.444¢ per kWh for all kWh
<u>Non-Capacity Energy</u>	<u>(June – September)</u>
Summer On Peak	9.236¢ per kWh for all kWh
Summer Off Peak	5.509¢ per kWh for all kWh
<u>Non-Capacity Energy</u>	<u>(October – May)</u>
Non-Summer On Peak	5.894¢ per kWh for all kWh
Non-Summer Off Peak	5.509¢ per kWh for all kWh

On-Peak Hours: *All kWh used between 1:00PM and 5:00PM Monday through Friday.*

Off-Peak Hours: *All other kWh used.*

Delivery Charges:

<u>Service Charge:</u>	<u>\$11.25 per month</u>
<u>Distribution Charge:</u>	<u>6.156¢ per kWh for all kWh</u>

Surcharges and Credits: *As approved by the Commission. See Sections C8.5 and C9.8.*

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

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RATE SCHEDULE NO. D3.11 (Contd.)

GENERAL SERVICE TIME OF USE RATE

Capacity Energy (June – September)

Summer On Peak 4.098¢ per kWh for all kWh

Summer Off Peak 2.444¢ per kWh for all kWh

Capacity Energy (October – May)

Non-Summer On Peak 2.615¢ per kWh for all kWh

Non-Summer Off Peak 2.444¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: 6.156¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

LATE PAYMENT CHARGE: See Section C4.8.

CONTRACT TERM: Upon enrollment customers are required to remain on rate for 12 months. After 12 months, open order, terminable on three days' written notice by either party.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: 12 months, terminable on three days' written notice by either party. Where special services are required, or where the investment to serve is out of proportion to the revenue derived therefrom, the term will be as specified in the applicable contract rider.

WATER HEATING SERVICE: Water heating service is available on an optional basis. See Schedule Designation No. D5.

INTERRUPTIBLE SPACE-CONDITIONING PROVISION: Rate D1.1 is available for commercial space-conditioning use. This provision is applicable to central air-conditioning and heat pump use. All other provisions of D3.11 shall apply.

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RATE SCHEDULE NO. D4**LARGE GENERAL SERVICE RATE**

AVAILABILITY OF SERVICE: Available to customers desiring service for any purpose, except that this rate is not available for service in conjunction with the General Service Rate.

Effective May 27, 1981, this rate is not available to customers desiring service through one meter for residential purposes to a single or double occupancy dwelling unit.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 120/240 volts, three-wire; or three-phase four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase four-wire, Y connected at 480Y/277 volts.

In certain city districts, alternating current is supplied from a Y connected secondary network from which 120/208 volts, single-phase three-wire; or 208Y/120 volts, three-phase four-wire service may be taken.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity Demand Charge:	\$ <u>9.18</u> ~~3.57~~ per kW applied to the Monthly Billing Demand
Non-Capacity Demand Charges:	\$ <u>8.07</u> ~~13.02~~ per kW applied to the Monthly Billing Demand
Non-Capacity Energy Charges:	<u>4.169</u> ~~4.012~~ ¢ per kWh for the first 200 kWh per kW of billing demand
	<u>3.219</u> ~~3.097~~ ¢ per kWh for the excess

Delivery Charges:

Service Charge:	\$13.67 per month
Distribution Demand Charge:	\$ <u>25.21</u> ~~21.80~~ per kW applied to the Monthly Billing Demand

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Demand Charge:	\$ <u>9.18</u> ~~3.57~~ per kW applied to the Monthly Billing Demand

Delivery Charges:

Service Charge:	\$13.67 per month
Distribution Demand Charge:	\$ <u>25.21</u> ~~21.80~~ per kW applied to the Monthly Billing Demand

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RATE SCHEDULE NO. D5

WATER HEATING SERVICE RATE

AVAILABILITY OF SERVICE: Available to customers using hot water for sanitary purposes (other uses subject to the approval of the Company) and taking service under Residential and General Service Rate Schedules. This rate is also available to customers with solar assisted hot water heaters. Company approved waste heat reclamation systems and heat pump water heaters when used in conjunction with an approved electric water heater are also acceptable for use.

Available to customers who desire controlled water heating service to all of the heating elements of electric water heaters, the design and method of installation of which are approved by the Company as adapted to this service, taken through a separately metered circuit to which no other load except water heating may be connected. Customers who take service on this tariff are not eligible to participate in another Demand Response program with an Aggregator of Retail Customer (ARC) in any MISO season.

HOURS OF SERVICE: 24 hours.

HOURS OF INTERRUPTION: Interruptions may be called for, but not limited to, system testing and evaluation, maintaining system integrity, ~~making an emergency purchase~~, economic reasons, or when available system generation is insufficient to meet anticipated system load. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for emergency electrical procedures under Section C3. The Company will limit interruptions to intervals of no longer than 4 hours in any 24-hour period.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, nominally at 240 volts, three-wire, except that, in certain city districts, alternating current service at 208 volts, nominal, three-wire, or three-phase at the option of the Company.

RATE PER MONTH:

Full Service Customers:

Residential Power Supply Charges:

Capacity Energy Charge: ~~1.805~~~~0.698~~¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~3.303~~~~4.132~~¢ per kWh for all kWh

Residential Delivery Charges:

Service Charge: \$1.95 per month

Distribution Charge: ~~9.451~~~~8.137~~¢ per kWh for all kWh

Commercial Power Supply Charges:

Capacity Energy Charge: ~~1.534~~~~0.595~~¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~3.457~~~~4.178~~¢ per kWh for all kWh

Commercial Delivery Charges:

Service Charge: \$1.95 per month

Distribution Charge: ~~6.156~~~~5.288~~¢ per kWh for all kWh

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RATE SCHEDULE NO. D5 (Contd.)

WATER HEATING SERVICE RATE

Retail Access Service Customers:

Residential Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: ~~1.8050-698¢~~ per kWh for all kWh

Residential Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE (contd):

Residential Delivery Charges:

Service Charge: \$1.95 per month

Distribution Charge: ~~9.4518-137¢~~ per kWh for all kWh

Commercial Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: ~~1.5340-595¢~~ per kWh for all kWh

Commercial Delivery Charges:

Service Charge: \$1.95 per month

Distribution Charge: ~~6.1565-288¢~~ per kWh for all kWh

SURCHARGES AND CREDITS: As approved by the Commission. Power Supply Charges are subject to Section C8.5. Delivery Charges are subject to Section C9.8. Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

CONTRACT TERM: Open order, terminable on three days' notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

WATER HEATER REQUIREMENTS FOR WATER HEATER RATE APPLICATION:

<u>Rate Option</u>	<u>Minimum Tank Capacity*</u>	<u>Maximum Total Connected Load**</u>
Residential	30 gallons	5.5 kW
<u>Rate Option</u>	<u>Minimum Tank Capacity*</u>	<u>Maximum Total Connected Load**</u>
Commercial	2 gallons per kW of total connected load 40 gallon minimum	Controlled by minimum tank capacity requirements

*No limitation to number of tanks

**Single or multi-element

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RATE SCHEDULE NO. D6.2

PRIMARY EDUCATIONAL INSTITUTION RATE

AVAILABILITY OF SERVICE: Available to Educational Institution (school, college, university) customer locations desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location. 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 owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Demand Charge: \$10.79 ~~3.58~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.45 ~~0.15~~ per kW at transmission level

\$0.22 ~~0.07~~ per kW at subtransmission level

Non-Capacity

Demand Charge: \$ 4.56 ~~10.04~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.19 ~~0.40~~ per kW at transmission level

\$0.09 ~~0.18~~ per kW at subtransmission level

Energy Charges: 4.837 ~~4.322~~¢ per kWh for all on-peak kWh

4.537 ~~4.022~~¢ per kWh for all off-peak kWh

Voltage Level Discount:

0.182 ~~0.162~~¢ per kWh at transmission level

0.082 ~~0.073~~¢ per kWh at subtransmission level

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RATE SCHEDULE NO. D6.2 (Contd.)

PRIMARY EDUCATIONAL INSTITUTION RATE

Full Service Customers (Contd):

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) ~~\$6.66~~ ~~6.15~~ per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) ~~\$1.82~~ ~~1.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) ~~\$0.99~~ ~~0.86~~ per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving utility Capacity Service from DTE Electric)

Demand Charge: ~~\$10.79~~ ~~3.58~~ per kW of on-peak billing demand

Voltage Level Discount:

~~\$0.45~~ ~~0.15~~ per kW of on-peak billing demand at transmission level

~~\$0.22~~ ~~0.07~~ per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) ~~\$6.66~~ ~~6.15~~ per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) ~~\$1.82~~ ~~1.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) ~~\$0.99~~ ~~0.86~~ per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

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RATE SCHEDULE NO. D8 (Contd.)

INTERRUPTIBLE SUPPLY RATE

NON-INTERRUPTION FEE: Customers who do not interrupt by the effective start time of a capacity deficiency order shall be billed at the cost of replacement energy plus 0.576¢ per kWh during the time of interruption plus the applicable voltage level charge, but not less than the normal D8 rate. Voltage level charges for service other than transmission voltage are:

0. ~~143~~¹³⁸¢ per kWh at the distribution level.

0. ~~079~~⁰⁷⁶¢ per kWh at the subtransmission level.

SYSTEM INTEGRITY INTERRUPTION ORDER:

NOTICE OF SYSTEM INTEGRITY INTERRUPTION: The customer shall be provided:

- 1) Notice at least 1 hour in advance of probable interruption, whenever possible;
- 2) The time in which customer must fully reduce load; and
- 3) The estimated duration of the interruption.

The customer shall be provided notice of the actual end time for the system integrity order.

NON-INTERRUPTION PENALTY: A customer who does not fully comply with the timing and load reduction prescribed in the Notice of System Integrity Interruption shall be billed at the higher of (i) the rate of \$50 per kW applied to the highest 60-minute integrated interruptible demand (kW) created during the interruption period or (ii) the actual damages incurred by the Company, including any MISO penalties in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not fully comply with a System Integrity interruption order may be immediately reduced by the amount the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-41.00)

Issued _____, 2025

M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

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in Case No. U-21534

(Continued from Sheet No. D-41.00)

RATE SCHEDULE NO. D8 (Contd.)

INTERRUPTIBLE SUPPLY RATE

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Demand Charge: \$4.24 ~~1.62~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.18 ~~0.07~~ per kW of on-peak billing demand at transmission level

\$0.09 ~~0.03~~ per kW of on-peak billing demand at subtransmission level

Non-Capacity

Demand Charge: \$6.00 ~~8.50~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.25 ~~0.33~~ per kW of on-peak billing demand at transmission level

\$0.12 ~~0.15~~ per kW of on-peak billing demand at subtransmission level

Energy Charge:

4.388 ~~4.257~~¢ per kWh for all on-peak kWh

3.388 ~~3.257~~¢ per kWh for all off-peak kWh

Voltage Level Discount:

0.143 ~~0.138~~¢ per kWh at transmission level

0.064 ~~0.062~~¢ per kWh at subtransmission level

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) \$6.66 ~~6.15~~ per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) \$1.82 ~~1.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) \$0.99 ~~0.86~~ per kW of maximum demand.

(Continued on Sheet No. D-42.00)

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(Continued from Sheet No. D-41.00)

RATE SCHEDULE NO. D8 (Contd.)

INTERRUPTIBLE SUPPLY RATE

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service customers:

Capacity (only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Demand Charge: \$4.24 ~~1.62~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.18 ~~0.07~~ per kW of on-peak billing demand at transmission level

\$0.09 ~~0.03~~ per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) \$6.66 ~~6.15~~ per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) \$1.82 ~~1.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) \$0.99 ~~0.86~~ per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. In no event will the monthly on-peak billing demand be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts.

(Continued on Sheet No. D-43.00)

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(Continued from Sheet No. D-44.00)

RATE SCHEDULE NO. D9

OUTDOOR PROTECTIVE LIGHTING

SPECIAL TERMS AND CONDITIONS (contd.):

The stated charges for underground service on Sheet No. D-46.00 cover the ordinary trenching for cable extensions under normal soil conditions in cleared areas.

- (1) Special purpose facilities are considered to be line or cable extensions, transformers, and any additional poles without lights, excluding facilities provided under stated charges on Sheet No. D-45.00. Where special purpose facilities are required, a service charge of 18% per year on the investment in such facilities will be billed in installments as an addition to the regular rate for each light. In the event the customer discontinues service before the end of the contract term, the established rate as well as the service charge on special purpose facilities for the remaining portion of the contract term shall immediately become due and payable. This provision was closed to new installations as of January 22, 1994.
- (2) For new installations after January 22, 1994, which require investment in excess of three times the annual revenue, this rate is available only to customers who make a contribution in aid of construction equal to the amount by which the investment exceeds three times the annual revenue at the prevailing rate at the time of installation.
- (3) For new underground-fed installations of 5 lights or more after May 1, 2019, which require investment in excess of three times the annual revenue, the customer may elect to pay a post charge for each increment of \$1,000 investment required above three times the annual revenue.
- (4) As an alternative, where the required contribution exceeds \$10,000, upon agreement of the customer and the Company, the customer will pay an additional annual charge of the Company's weighted average cost of capital (~~6.92~~7.37%) times the contribution amount in lieu of the cash contribution.

DE-ENERGIZED LIGHTS: Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 60% of the regular yearly rates. A \$35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.

DUSK TO MIDNIGHT SERVICE: For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours of use will be applied. One control per circuit or luminaire will be provided.

EXPERIMENTAL PROGRAMMABLE PHOTOCELL SERVICE: Customers may elect to place luminaires on photocells that are programmable to turn off lights at pre-determined times during the night. A distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours of use will be applied.

MONTHLY RATES: Overhead Outdoor Protective Lighting with Existing Pole and Existing Secondary Facilities (All-night service).

Power Supply Charges:

Capacity Energy Charge:	0.00¢ per kWh for all kWh
Non-Capacity Energy Charge:	~~4.6~~ <u>4.6</u> ¢ per kWh for all kWh

(Continued on Sheet No. D-45.01)

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(Continued from Sheet No. D-45.00)

RATE SCHEDULE NO. D9 (Contd.)

OUTDOOR PROTECTIVE LIGHTING

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
100 W	Mercury Vapor	~~\$16.13~~ ^{~~\$5.04~~}	120	350	\$0.04646	~~\$1.96~~ ^{~~\$1.87~~}	~~\$18.09~~ ^{~~\$6.91~~}
175 W	Mercury Vapor	~~\$20.05~~ ^{~~\$18.68~~}	210	350	\$0.04646	~~\$3.43~~ ^{~~\$3.28~~}	~~\$23.48~~ ^{~~\$21.95~~}
250 W	Mercury Vapor	~~\$23.98~~ ^{~~\$22.32~~}	300	350	\$0.04646	~~\$4.90~~ ^{~~\$4.68~~}	~~\$28.88~~ ^{~~\$27.00~~}
400 W	Mercury Vapor	~~\$31.61~~ ^{~~\$29.40~~}	450	350	\$0.04646	~~\$7.35~~ ^{~~\$7.02~~}	~~\$38.95~~ ^{~~\$36.42~~}
1,000 W	Mercury Vapor	~~\$64.81~~ ^{~~\$60.24~~}	1060	350	\$0.04646	~~\$17.31~~ ^{~~\$16.53~~}	~~\$82.12~~ ^{~~\$76.78~~}
100 W	High Pressure Sodium	~~\$15.02~~ ^{~~\$14.00~~}	135	350	\$0.04646	~~\$2.20~~ ^{~~\$2.11~~}	~~\$17.23~~ ^{~~\$16.10~~}
150 W	High Pressure Sodium	~~\$17.94~~ ^{~~\$16.71~~}	200	350	\$0.04646	~~\$3.27~~ ^{~~\$3.12~~}	~~\$21.21~~ ^{~~\$19.83~~}
250 W	High Pressure Sodium	~~\$23.09~~ ^{~~\$21.49~~}	305	350	\$0.04646	~~\$4.98~~ ^{~~\$4.76~~}	~~\$28.07~~ ^{~~\$26.25~~}
400 W	High Pressure Sodium	~~\$28.42~~ ^{~~\$26.42~~}	465	350	\$0.04646	~~\$7.59~~ ^{~~\$7.25~~}	~~\$36.02~~ ^{~~\$33.68~~}
1,000 W	High Pressure Sodium	~~\$57.35~~ ^{~~\$53.23~~}	1100	350	\$0.04646	~~\$17.96~~ ^{~~\$17.16~~}	~~\$75.29~~ ^{~~\$70.38~~}
100 W	Metal Halide	~~\$15.06~~ ^{~~\$14.03~~}	120	350	\$0.04646	~~\$1.96~~ ^{~~\$1.87~~}	~~\$17.02~~ ^{~~\$15.90~~}
150 W	Metal Halide	~~\$18.01~~ ^{~~\$16.77~~}	180	350	\$0.04646	~~\$2.94~~ ^{~~\$2.81~~}	~~\$20.95~~ ^{~~\$19.58~~}
175 W	Metal Halide	~~\$19.49~~ ^{~~\$18.14~~}	210	350	\$0.04646	~~\$3.43~~ ^{~~\$3.28~~}	~~\$22.92~~ ^{~~\$21.42~~}
250 W	Metal Halide	~~\$23.91~~ ^{~~\$22.25~~}	300	350	\$0.04646	~~\$4.90~~ ^{~~\$4.68~~}	~~\$28.81~~ ^{~~\$26.93~~}
320 W	Metal Halide	~~\$28.04~~ ^{~~\$26.09~~}	365	350	\$0.04646	~~\$5.96~~ ^{~~\$5.69~~}	~~\$34.00~~ ^{~~\$31.78~~}
400 W	Metal Halide	~~\$32.76~~ ^{~~\$30.48~~}	460	350	\$0.04646	~~\$7.51~~ ^{~~\$7.17~~}	~~\$40.27~~ ^{~~\$37.65~~}
1,000 W	Metal Halide	~~\$68.16~~ ^{~~\$63.38~~}	1050	350	\$0.04646	~~\$17.14~~ ^{~~\$16.38~~}	~~\$85.31~~ ^{~~\$79.75~~}
20 - 29 W	LED	~~\$12.00~~ ^{~~\$11.20~~}	25	350	\$0.04646	~~\$0.41~~ ^{~~\$0.39~~}	~~\$12.41~~ ^{~~\$11.59~~}
30 - 39 W	LED	~~\$12.62~~ ^{~~\$11.79~~}	35	350	\$0.04646	~~\$0.57~~ ^{~~\$0.55~~}	~~\$13.19~~ ^{~~\$12.33~~}
40 - 49 W	LED	~~\$13.25~~ ^{~~\$12.37~~}	45	350	\$0.04646	~~\$0.73~~ ^{~~\$0.70~~}	~~\$13.98~~ ^{~~\$13.07~~}
50 - 59 W	LED	~~\$13.87~~ ^{~~\$12.95~~}	55	350	\$0.04646	~~\$0.90~~ ^{~~\$0.86~~}	~~\$14.77~~ ^{~~\$13.81~~}
60 - 69 W	LED	~~\$14.49~~ ^{~~\$13.53~~}	65	350	\$0.04646	~~\$1.06~~ ^{~~\$1.01~~}	~~\$15.55~~ ^{~~\$14.55~~}
70 - 79 W	LED	~~\$15.13~~ ^{~~\$14.12~~}	75	350	\$0.04646	~~\$1.22~~ ^{~~\$1.17~~}	~~\$16.35~~ ^{~~\$15.29~~}
80 - 89 W	LED	~~\$15.75~~ ^{~~\$14.70~~}	85	350	\$0.04646	~~\$1.39~~ ^{~~\$1.33~~}	~~\$17.14~~ ^{~~\$16.03~~}
90 - 99 W	LED	~~\$16.38~~ ^{~~\$15.28~~}	95	350	\$0.04646	~~\$1.55~~ ^{~~\$1.48~~}	~~\$17.93~~ ^{~~\$16.76~~}
100 - 109 W	LED	~~\$17.01~~ ^{~~\$15.86~~}	105	350	\$0.04646	~~\$1.71~~ ^{~~\$1.64~~}	~~\$18.72~~ ^{~~\$17.50~~}
110 - 119 W	LED	~~\$17.63~~ ^{~~\$16.45~~}	115	350	\$0.04646	~~\$1.88~~ ^{~~\$1.79~~}	~~\$19.51~~ ^{~~\$18.24~~}
120 - 129 W	LED	~~\$18.26~~ ^{~~\$17.03~~}	125	350	\$0.04646	~~\$2.04~~ ^{~~\$1.95~~}	~~\$20.30~~ ^{~~\$18.98~~}
130 - 139 W	LED	~~\$18.88~~ ^{~~\$17.61~~}	135	350	\$0.04646	~~\$2.20~~ ^{~~\$2.11~~}	~~\$21.09~~ ^{~~\$19.72~~}
140 - 149 W	LED	~~\$19.45~~ ^{~~\$18.14~~}	145	350	\$0.04646	~~\$2.37~~ ^{~~\$2.26~~}	~~\$21.82~~ ^{~~\$20.40~~}
150 - 159 W	LED	~~\$20.02~~ ^{~~\$18.66~~}	155	350	\$0.04646	~~\$2.53~~ ^{~~\$2.42~~}	~~\$22.55~~ ^{~~\$21.08~~}
160 - 169 W	LED	~~\$20.58~~ ^{~~\$19.18~~}	165	350	\$0.04646	~~\$2.69~~ ^{~~\$2.57~~}	~~\$23.27~~ ^{~~\$21.76~~}
170 - 179 W	LED	~~\$21.14~~ ^{~~\$19.71~~}	175	350	\$0.04646	~~\$2.86~~ ^{~~\$2.73~~}	~~\$24.00~~ ^{~~\$22.44~~}
180 - 189 W	LED	~~\$21.71~~ ^{~~\$20.23~~}	185	350	\$0.04646	~~\$3.02~~ ^{~~\$2.89~~}	~~\$24.73~~ ^{~~\$23.12~~}
190 - 199 W	LED	~~\$22.27~~ ^{~~\$20.75~~}	195	350	\$0.04646	~~\$3.18~~ ^{~~\$3.04~~}	~~\$25.45~~ ^{~~\$23.80~~}
200 - 209 W	LED	~~\$22.83~~ ^{~~\$21.28~~}	205	350	\$0.04646	~~\$3.35~~ ^{~~\$3.20~~}	~~\$26.18~~ ^{~~\$24.47~~}
210 - 219 W	LED	~~\$23.39~~ ^{~~\$21.80~~}	215	350	\$0.04646	~~\$3.51~~ ^{~~\$3.35~~}	~~\$26.90~~ ^{~~\$25.15~~}
220 - 229 W	LED	~~\$23.95~~ ^{~~\$22.32~~}	225	350	\$0.04646	~~\$3.67~~ ^{~~\$3.51~~}	~~\$27.63~~ ^{~~\$25.83~~}
230 - 239 W	LED	~~\$24.52~~ ^{~~\$22.85~~}	235	350	\$0.04646	~~\$3.84~~ ^{~~\$3.67~~}	~~\$28.36~~ ^{~~\$26.51~~}
240 - 249 W	LED	~~\$25.09~~ ^{~~\$23.37~~}	245	350	\$0.04646	~~\$4.00~~ ^{~~\$3.82~~}	~~\$29.09~~ ^{~~\$27.19~~}

(Continued on Sheet No. D-45.02)

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Regulatory Affairs

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(Continued from Sheet No. D-45.01)

RATE SCHEDULE NO. D9 (Contd.)

OUTDOOR PROTECTIVE LIGHTING

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
250 - 259 W	LED	~~\$25.65~~ ~~23.89~~	255	350	\$0.04 ~~646~~	~~\$4.16~~ ~~3.98~~	~~\$29.81~~ ~~27.87~~
260 - 269 W	LED	~~\$26.21~~ ~~24.42~~	265	350	\$0.04 ~~646~~	~~\$4.33~~ ~~4.13~~	~~\$30.54~~ ~~28.55~~
270 - 279 W	LED	~~\$26.78~~ ~~24.94~~	275	350	\$0.04 ~~646~~	~~\$4.49~~ ~~4.29~~	~~\$31.27~~ ~~29.23~~
280 - 289 W	LED	~~\$27.34~~ ~~25.47~~	285	350	\$0.04 ~~646~~	~~\$4.65~~ ~~4.44~~	~~\$32.00~~ ~~29.91~~
290 - 299 W	LED	~~\$27.90~~ ~~25.99~~	295	350	\$0.04 ~~646~~	~~\$4.82~~ ~~4.60~~	~~\$32.72~~ ~~30.59~~
300 - 309 W	LED	~~\$28.47~~ ~~26.51~~	305	350	\$0.04 ~~646~~	~~\$4.98~~ ~~4.76~~	~~\$33.44~~ ~~31.27~~
310 - 319 W	LED	~~\$29.03~~ ~~27.04~~	315	350	\$0.04 ~~646~~	~~\$5.14~~ ~~4.91~~	~~\$34.17~~ ~~31.95~~
320 - 329 W	LED	~~\$29.59~~ ~~27.56~~	325	350	\$0.04 ~~646~~	~~\$5.31~~ ~~5.07~~	~~\$34.90~~ ~~32.63~~
330 - 339 W	LED	~~\$30.15~~ ~~28.08~~	335	350	\$0.04 ~~646~~	~~\$5.47~~ ~~5.22~~	~~\$35.62~~ ~~33.31~~
340 - 349 W	LED	~~\$30.72~~ ~~28.61~~	345	350	\$0.04 ~~646~~	~~\$5.63~~ ~~5.38~~	~~\$36.35~~ ~~33.99~~
350 - 359 W	LED	~~\$31.28~~ ~~29.13~~	355	350	\$0.04 ~~646~~	~~\$5.80~~ ~~5.54~~	~~\$37.08~~ ~~34.67~~
360 - 369 W	LED	~~\$31.84~~ ~~29.65~~	365	350	\$0.04 ~~646~~	~~\$5.96~~ ~~5.69~~	~~\$37.80~~ ~~35.35~~
370 - 379 W	LED	~~\$32.41~~ ~~30.18~~	375	350	\$0.04 ~~646~~	~~\$6.12~~ ~~5.85~~	~~\$38.53~~ ~~36.03~~
380 - 389 W	LED	~~\$32.97~~ ~~30.70~~	385	350	\$0.04 ~~646~~	~~\$6.29~~ ~~6.00~~	~~\$39.25~~ ~~36.70~~
390 - 399 W	LED	~~\$33.53~~ ~~31.22~~	395	350	\$0.04 ~~646~~	~~\$6.45~~ ~~6.16~~	~~\$39.98~~ ~~37.38~~

For installations prior to January 22, 1994. New Pole and Single Span of Secondary Facilities. The above rate plus \$24.48 per pole per year.

Effective January 22, 1994 installation requiring additional facilities shall pay a contribution in aid of construction in lieu of the service charge. Contribution is described in paragraph (2) above.

Multiple Lamps on a Single Pole. For each additional luminaire added to the same pole the charge will be at the existing pole rate.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those fixtures fail. At that time, the luminaire will be converted to LED.

MONTHLY RATES: Underground Outdoor Protective Lighting with Lamp Spacing up to 120 Feet (All-night service).

Power Supply Charges:

Capacity Energy Charge: 0.00¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~4.66~~~~4.46~~¢ per kWh for all kWh

(Continued on Sheet No. D-46.00)

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(Continued from Sheet No. D-45.02)

RATE SCHEDULE NO. D9 (Contd.)

OUTDOOR PROTECTIVE LIGHTING

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
100 W	Mercury Vapor	\$27.51 ~~27.60~~	120	350	\$0.04646	\$1.961 ~~1.87~~	\$29.47 ~~29.47~~
175 W	Mercury Vapor	\$30.20 ~~30.35~~	210	350	\$0.04646	\$3.433 ~~3.28~~	\$33.63 ~~33.62~~
250 W	Mercury Vapor	\$35.43 ~~35.65~~	300	350	\$0.04646	\$4.904 ~~4.68~~	\$40.33 ~~40.33~~
400 W	Mercury Vapor	\$45.93 ~~46.25~~	450	350	\$0.04646	\$7.357 ~~7.02~~	\$53.27 ~~53.27~~
1,000 W	Mercury Vapor	\$85.76 ~~86.55~~	1060	350	\$0.04646	\$17.314 ~~16.53~~	\$103.06 ~~103.08~~
70 W	High Pressure Sodium	\$24.02 ~~24.09~~	95	350	\$0.04646	\$1.551 ~~1.48~~	\$25.57 ~~25.57~~
100 W	High Pressure Sodium	\$24.76 ~~24.86~~	135	350	\$0.04646	\$2.202 ~~2.11~~	\$26.97 ~~26.96~~
150 W	High Pressure Sodium	\$26.35 ~~26.49~~	200	350	\$0.04646	\$3.273 ~~3.12~~	\$29.62 ~~29.61~~
250 W	High Pressure Sodium	\$29.53 ~~29.75~~	305	350	\$0.04646	\$4.984 ~~4.76~~	\$34.51 ~~34.51~~
400 W	High Pressure Sodium	\$34.30 ~~34.64~~	465	350	\$0.04646	\$7.597 ~~7.25~~	\$41.89 ~~41.90~~
1,000 W	High Pressure Sodium	\$53.37 ~~54.21~~	1100	350	\$0.04646	\$17.961 ~~17.16~~	\$71.33 ~~71.37~~
100 W	Metal Halide	\$24.76 ~~24.86~~	120	350	\$0.04646	\$1.961 ~~1.87~~	\$26.72 ~~26.72~~
150 W	Metal Halide	\$26.35 ~~26.49~~	180	350	\$0.04646	\$2.942 ~~2.81~~	\$29.29 ~~29.10~~
175 W	Metal Halide	\$27.15 ~~27.17~~	210	350	\$0.04646	\$3.433 ~~3.28~~	\$30.58 ~~30.44~~
250 W	Metal Halide	\$29.53 ~~29.75~~	300	350	\$0.04646	\$4.904 ~~4.68~~	\$34.43 ~~34.47~~
400 W	Metal Halide	\$34.30 ~~34.64~~	460	350	\$0.04646	\$7.517 ~~7.17~~	\$41.81 ~~41.81~~
1,000 W	Metal Halide	\$101.94 ~~98.08~~	1050	350	\$0.04646	\$17.144 ~~16.38~~	\$119.08 ~~114.45~~
20 - 29 W	LED	\$25.20 ~~25.22~~	25	350	\$0.04646	\$0.410 ~~0.39~~	\$25.61 ~~25.61~~
30 - 39 W	LED	\$25.63 ~~25.66~~	35	350	\$0.04646	\$0.570 ~~0.55~~	\$26.21 ~~26.21~~
40 - 49 W	LED	\$26.07 ~~26.10~~	45	350	\$0.04646	\$0.730 ~~0.70~~	\$26.81 ~~26.80~~
50 - 59 W	LED	\$26.51 ~~26.55~~	55	350	\$0.04646	\$0.900 ~~0.86~~	\$27.41 ~~27.40~~
60 - 69 W	LED	\$26.95 ~~27.00~~	65	350	\$0.04646	\$1.061 ~~1.01~~	\$28.01 ~~28.01~~
70 - 79 W	LED	\$27.36 ~~27.41~~	75	350	\$0.04646	\$1.221 ~~1.17~~	\$28.58 ~~28.58~~
80 - 89 W	LED	\$27.78 ~~27.84~~	85	350	\$0.04646	\$1.391 ~~1.33~~	\$29.17 ~~29.16~~
90 - 99 W	LED	\$28.18 ~~28.25~~	95	350	\$0.04646	\$1.551 ~~1.48~~	\$29.73 ~~29.73~~
100 - 109 W	LED	\$28.58 ~~28.66~~	105	350	\$0.04646	\$1.711 ~~1.64~~	\$30.30 ~~30.30~~
110 - 119 W	LED	\$29.01 ~~29.09~~	115	350	\$0.04646	\$1.881 ~~1.79~~	\$30.89 ~~30.88~~
120 - 129 W	LED	\$29.40 ~~29.49~~	125	350	\$0.04646	\$2.041 ~~1.95~~	\$31.44 ~~31.44~~
130 - 139 W	LED	\$29.79 ~~29.89~~	135	350	\$0.04646	\$2.202 ~~2.11~~	\$32.00 ~~31.99~~
140 - 149 W	LED	\$30.17 ~~30.27~~	145	350	\$0.04646	\$2.372 ~~2.26~~	\$32.53 ~~32.53~~
150 - 159 W	LED	\$30.54 ~~30.65~~	155	350	\$0.04646	\$2.532 ~~2.42~~	\$33.07 ~~33.07~~
160 - 169 W	LED	\$30.92 ~~31.03~~	165	350	\$0.04646	\$2.692 ~~2.57~~	\$33.61 ~~33.60~~
170 - 179 W	LED	\$31.29 ~~31.41~~	175	350	\$0.04646	\$2.862 ~~2.73~~	\$34.15 ~~34.14~~
180 - 189 W	LED	\$31.66 ~~31.79~~	185	350	\$0.04646	\$3.022 ~~2.89~~	\$34.68 ~~34.68~~
190 - 199 W	LED	\$32.04 ~~32.17~~	195	350	\$0.04646	\$3.183 ~~3.04~~	\$35.22 ~~35.22~~
200 - 209 W	LED	\$32.41 ~~32.56~~	205	350	\$0.04646	\$3.353 ~~3.20~~	\$35.76 ~~35.75~~
210 - 219 W	LED	\$32.79 ~~32.94~~	215	350	\$0.04646	\$3.513 ~~3.35~~	\$36.30 ~~36.29~~
220 - 229 W	LED	\$33.16 ~~33.32~~	225	350	\$0.04646	\$3.673 ~~3.51~~	\$36.83 ~~36.83~~
230 - 239 W	LED	\$33.53 ~~33.70~~	235	350	\$0.04646	\$3.843 ~~3.67~~	\$37.37 ~~37.37~~
240 - 249 W	LED	\$33.91 ~~34.08~~	245	350	\$0.04646	\$4.003 ~~3.82~~	\$37.91 ~~37.91~~
250 - 259 W	LED	\$34.28 ~~34.47~~	255	350	\$0.04646	\$4.163 ~~3.98~~	\$38.45 ~~38.44~~
260 - 269 W	LED	\$34.66 ~~34.85~~	265	350	\$0.04646	\$4.334 ~~4.13~~	\$38.98 ~~38.98~~

(Continued on Sheet No. D-46.01)

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(Continued from Sheet No. D-46.00)

RATE SCHEDULE NO. D9 (Contd.)

OUTDOOR PROTECTIVE LIGHTING

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
270 - 279 W	LED	~~\$35.03~~ ~~35.23~~	275	350	~~\$0.046~~ ~~46~~	~~\$4.49~~ ~~4.29~~	~~\$39.52~~ ~~39.52~~
280 - 289 W	LED	~~\$35.41~~ ~~35.61~~	285	350	~~\$0.046~~ ~~46~~	~~\$4.65~~ ~~4.44~~	~~\$40.06~~ ~~40.05~~
290 - 299 W	LED	~~\$35.78~~ ~~35.99~~	295	350	~~\$0.046~~ ~~46~~	~~\$4.82~~ ~~4.60~~	~~\$40.59~~ ~~40.59~~
300 - 309 W	LED	~~\$36.15~~ ~~36.37~~	305	350	~~\$0.046~~ ~~46~~	~~\$4.98~~ ~~4.76~~	~~\$41.13~~ ~~41.13~~
310 - 319 W	LED	~~\$36.52~~ ~~36.76~~	315	350	~~\$0.046~~ ~~46~~	~~\$5.14~~ ~~4.91~~	~~\$41.67~~ ~~41.67~~
320 - 329 W	LED	~~\$36.90~~ ~~37.14~~	325	350	~~\$0.046~~ ~~46~~	~~\$5.31~~ ~~5.07~~	~~\$42.20~~ ~~42.21~~
330 - 339 W	LED	~~\$37.27~~ ~~37.52~~	335	350	~~\$0.046~~ ~~46~~	~~\$5.47~~ ~~5.22~~	~~\$42.74~~ ~~42.74~~
340 - 349 W	LED	~~\$37.64~~ ~~37.90~~	345	350	~~\$0.046~~ ~~46~~	~~\$5.63~~ ~~5.38~~	~~\$43.28~~ ~~43.28~~
350 - 359 W	LED	~~\$38.02~~ ~~38.28~~	355	350	~~\$0.046~~ ~~46~~	~~\$5.80~~ ~~5.54~~	~~\$43.81~~ ~~43.82~~
360 - 369 W	LED	~~\$38.39~~ ~~38.66~~	365	350	~~\$0.046~~ ~~46~~	~~\$5.96~~ ~~5.69~~	~~\$44.35~~ ~~44.36~~
370 - 379 W	LED	~~\$38.76~~ ~~39.05~~	375	350	~~\$0.046~~ ~~46~~	~~\$6.12~~ ~~5.85~~	~~\$44.88~~ ~~44.89~~
380 - 389 W	LED	~~\$39.13~~ ~~39.43~~	385	350	~~\$0.046~~ ~~46~~	~~\$6.29~~ ~~6.00~~	~~\$45.42~~ ~~45.43~~
390 - 399 W	LED	~~\$39.51~~ ~~39.81~~	395	350	~~\$0.046~~ ~~46~~	~~\$6.45~~ ~~6.16~~	~~\$45.96~~ ~~45.97~~

Effective January 22, 1994 installation requiring additional facilities shall pay a contribution in aid of construction in lieu of the service charge. Contribution is described in paragraph (2) above.

Effective May 1, 2019, installations requiring additional facilities shall pay a post charge of ~~\$6.88~~~~7.08~~ per increment of \$1,000 of expense in lieu of contribution in aid of construction. Contribution is described in paragraph (3) above.

Long Span

- For lamp spacing over 120 feet up to 325 feet on the same side of street, add to rate per lamp per year \$24.48

Semi-Ornamental

- For Semi-Ornamental Systems which employ Ornamental Post Units served from overhead conductors, where such construction is practical, reduce rate per luminaire per year \$21.48

Multiple Luminaires on a Single Pole

- For additional luminaires added to the same pole, a reduced rate per luminaire per year on the added luminaire.
 - Ornamental \$97.92
 - Ornamental-Lamp spacing over 120 feet \$122.40
 - Semi-Ornamental \$76.56

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, the luminaire will be converted to LED.

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RATE SCHEDULE NO. D10

ALL-ELECTRIC SCHOOL BUILDING SERVICE RATE

AVAILABILITY OF SERVICE: Available to customers desiring service in school buildings served at primary voltage who contract for a specified installed capacity of not less than 50 kilowatts at a single location provided the space heating and water heating for all or a substantial portion of the premises is supplied by electric service and is installed on a permanent basis.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800 or 13,200 volts at the option of the Company.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charge (June through October): 3.458~~2.107~~¢ per kWh for all kWh

Energy Charge (November through May): 1.445~~0.094~~¢ per kWh for all kWh

Non-Capacity

Energy Charge (June through October): 6.384~~7.430~~¢ per kWh for all kWh

Energy Charge (November through May): 6.384~~7.430~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$70 per month

Distribution Charge: 1.973~~1.968~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charge (June through October): 3.458~~2.107~~¢ per kWh for all kWh

Energy Charge (November through May): 1.445~~0.094~~¢ per kWh for all kWh

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Service Charge: \$70 per month

Distribution Charge: 1.973~~1.968~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

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RATE SCHEDULE NO. D11

PRIMARY SUPPLY RATE

AVAILABILITY OF SERVICE: Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Demand Charge: \$9.19 ~~3.56~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.39 ~~0.15~~ per kW of on-peak billing demand at transmission level

\$0.19 ~~0.07~~ per kW of on-peak billing demand at subtransmission level

Non-Capacity

Demand Charge: \$8.35 ~~13.33~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.35 ~~0.53~~ per kW of on-peak billing demand at transmission level

\$0.17 ~~0.24~~ per kW of on-peak billing demand at subtransmission level

Energy Charge: 4.388 ~~4.257~~¢ per kWh for all on-peak kWh

3.388 ~~3.257~~¢ per kWh for all off-peak kWh

Voltage Level Discount:

0.143 ~~0.138~~¢ per kWh at transmission level

0.064 ~~0.062~~¢ per kWh at subtransmission level

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) \$6.66 ~~6.15~~ per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) \$1.82 ~~1.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) \$0.99 ~~0.86~~ per kW of maximum demand.

Continued on Sheet No. D-48.02)

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(Continued from Sheet No. D-48.01)

RATE SCHEDULE NO. D11 (Contd.)

PRIMARY SUPPLY RATE

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Demand Charge: \$9.19 ~~3.56~~ per kW of on-peak billing demand

Voltage Level Discount:

\$0.39 ~~0.15~~ per kW of on-peak billing demand at transmission level

\$0.19 ~~0.07~~ per kW of on-peak billing demand at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) \$6.66 ~~6.15~~ per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) \$1.82 ~~1.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) \$0.99 ~~0.86~~ per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period. The monthly on-peak billing demand will not be less than 65% of the highest monthly on-peak metered billing demand during

(Continued on Sheet No. D-48.03)

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RATE SCHEDULE NO. D12

**EXPERIMENTAL LARGE CUSTOMER
LOW PEAK DEMAND SUPPLY RATE**

AVAILABILITY OF SERVICE: Available on an experimental basis to new full-service customers with a minimum metered contract capacity of 10,000 kW and with high on-peak demands set during the October through May billing months and on-peak demands of ten percent (10%) or less during the June through September billing months and taking service at sub-transmission, or transmission voltage at a single location. Total contracted capacity on this tariff is limited to 100 MW. Service under this tariff may not be combined with any other tariff, rider, or separately metered service except for Rider Nos. 17 or 19.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 10,000 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity (October through May)

Demand Charge: \$0.33 ~~0.32~~ per kW of on-peak billing demand

Capacity (June through September)

Demand Charge: \$8.30 ~~8.00~~ per kW of on-peak billing demand

Capacity Voltage Level Discount:

\$(0.005) per kW of on-peak billing demand at transmission level (October through May)

\$(0.15) ~~0.14~~ per kW of on-peak billing demand at transmission level (June through September)

Non-Capacity (October through May)

Demand Charge: \$0.33 ~~0.32~~ per kW of on-peak billing demand

Non-Capacity (June through September)

Demand Charge: \$42.70 ~~41.16~~ per kW of on-peak billing demand

Non-Capacity Voltage Level Discount:

\$(0.005) per kW of on-peak billing demand at transmission level (October through May)

\$(0.73) ~~0.70~~ per kW of on-peak billing demand at transmission level (June through September)

(Continued on Sheet No. D-48.06)

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(Continued from Sheet No. D-48.05)

RATE SCHEDULE NO. D12 (contd.)

**EXPERIMENTAL LARGE CUSTOMER
LOW PEAK DEMAND SUPPLY RATE**

Energy Charge: ~~4.2654.112~~¢ per kWh for all on-peak kWh
~~3.7463.611~~¢ per kWh for all off-peak kWh

Energy Voltage Level Discount: ~~(0.0580.056)~~¢ per kWh at transmission level

Delivery Charges:

Subtransmission Service Charge: \$375 per month

Transmission Service Charge: \$375 per month

Distribution Charges:

For service at subtransmission voltage (24 to 41.6 kV) ~~\$1.821.96~~ per kW of maximum demand.

For service at transmission voltage (120 kV and above) ~~\$0.990.86~~ per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MONTHLY ON-PEAK BILLING DEMAND: The monthly on-peak billing demand shall be the single highest 30-minute integrated reading of the demand meter during the on-peak hours of the billing period, but not less than 50 kilowatts.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of contract capacity. This clause is applicable to each voltage level served.

MINIMUM CHARGE: All applicable demand charges plus the service charge and any applicable per meter per month surcharges.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

(Continued on Sheet No. D-48.07)

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RATE SCHEDULE NO. D13

XL HIGH LOAD FACTOR RATE

AVAILABILITY OF SERVICE: Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50,000 kilowatts, which may be located at one or more sites within the Company's electric service territory. The customer's load must reflect the following characteristics:

- 1) The contract capacity under this schedule must be new and incremental. Existing ("baseline") usage will remain eligible for service under any other rate schedule or rider for which it qualifies. The required incremental contracted capacity must be in service within four years of initially taking service under this rate.
- 2) Service taken by the customer must be at a load factor of no less than 75% for the capacity contracted under this rate. The required incremental load factor must be demonstrated in the twelve months following achievement of the contracted capacity described in (1) and maintained for the duration of service on this rate.
- 3) Any customer site taking service under this rate shall require separately metered circuits for such service.
- 4) Any customer failing to meet the incremental contract capacity and load factor requirement will be removed from this rate and placed on an eligible rate of the customer's choosing.
- 5) The rate is available at the discretion of the Company.

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CURRENT, PHASE AND VOLTAGE: Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in megawatts sufficient to meet normal maximum requirements but not less than 50,000 kilowatts. The customer may not exceed the contract capacity by more than 5%. Demand in excess of 105% of contract capacity will be placed on Rate Schedule No. D11, or any other eligible rate at the election of the customer. At the Company's discretion, it may offer to increase contract capacity on this rate without effect on the term of the contract. The contract capacity for customers served at more than one voltage level at one site shall be the sum of the contract capacities established for each voltage level.

The contract capacity, however established, shall not be decreased during the term of the contract except by mutual consent, and in no event may a decrease in contract capacity result in less than the minimum required capacity or load factor.

RATES:

Power Supply Charges for all service voltages

Capacity	\$15.14 / MWh
Non-Capacity	~~\$32.87~~ 34.30 / MWh
Transmission	~~\$3.08~~ 3.04 / MWh

Delivery Charge

Primary Service Charge	\$70 per meter/month
Subtransmission and Transmission Service Charge	\$375 per meter/month

(Continued on Sheet No. D-48.09)

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(Continued from Sheet No. D-48.08)

RATE SCHEDULE NO. D13 (contd.)

XL HIGH LOAD FACTOR RATE

RATES (contd.):

Distribution Charges

For primary service (less than 24 kV)	~~\$10.14~~ ~~9.36~~ / MWh
For service at sub-transmission voltage (24 to 41.6 kV)	~~\$2.77~~ ~~2.98~~ / MWh
For service at transmission voltage (120 kV and above)	~~\$1.51~~ ~~1.31~~ / MWh

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.55 per MWh shall be applied to the contracted load on this rate. A credit of \$0.40 per MWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Administration Charge

Administration	\$0.15 / MWh

Surcharges and Credits: Customers are subject to surcharges as approved by the Commission. Customers taking service on this rate are not subject to the Power Supply Cost Recovery (PSCR) factor, the Nuclear Surcharge, or the Transitional Reconciliation Mechanism. Customers taking service on this rate will be subject to an adjustment to reconcile projected and actual power supply non-capacity and transmission costs.

Other: The power supply capacity charge shall remain fixed for the term of the contract

BASELINE USAGE: Baseline usage is the Customer's existing contracted capacity at the time of taking service on D13. The Company reserves the right to define baseline usage based on exceptional circumstances as appropriate. Baseline usage may be served on any eligible rate schedule or rider, and it may in the future take service under any eligible rate or rider. No capacity or energy defined as baseline is eligible for service under this rate schedule and no capacity or energy may be moved from a baseline usage circuit to a circuit served under this rate.

DEFINITION OF LOAD FACTOR: For the purposes of this rate schedule Load Factor is defined on an annual basis. It is calculated as:

(Total MWh of usage in year / (incremental contract capacity in MW*hours in year))

POWER FACTOR CLAUSE: The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Any power factor less than 70% will not be permitted and the customer will be required to install at his own expense such corrective equipment as may be necessary to improve power factor. A penalty will be applied to the total amount of the monthly billing for electric energy for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The Power Factor Clause will be applied to metered quantities.

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RATE SCHEDULE NO. D14

PRIMARY TOU

AVAILABILITY OF SERVICE: *Available to customers desiring service at primary, sub-transmission, or transmission voltage who contract for a specified capacity of not less than 50 kilowatts at a single location. Contracted capacity on this rate is limited to 50 MW. This rate will be effective no later than December 31, 2025.*

HOURS OF SERVICE: *24 hours, subject to interruption by agreement, or by advance notice.*

CURRENT, PHASE AND VOLTAGE: *Alternating current, three-phase, nominally at 4,800, 13,200, 24,000, 41,570 or 120,000 volts at the option of the Company.*

CONTRACT CAPACITY: *Customers shall contract for a specified capacity in kilowatts sufficient to meet normal maximum requirements but not less than 50 kilowatts. The Company undertakes to provide the necessary facilities for a supply of electric power from its primary distribution system at the contract capacity. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for customers served at more than one voltage level shall be the sum of the contract capacities established for each voltage level.*

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

<u>Capacity Energy (June – September)</u>	
<u>Summer On Peak</u>	<u>2.649¢ per kWh for all kWh</u>
<u>Summer Off Peak</u>	<u>1.576¢ per kWh for all kWh</u>
<u>Capacity Energy (October – May)</u>	
<u>Non-Summer On Peak</u>	<u>1.831¢ per kWh for all kWh</u>
<u>Non-Summer Off Peak</u>	<u>1.576¢ per kWh for all kWh</u>

<u>Capacity Voltage Level Discount:</u>	
	<u>0.068¢ per kWh at transmission level</u>
	<u>0.030¢ per kWh at subtransmission level</u>

<u>Non-Capacity Energy (June – September)</u>	
<u>Summer On Peak</u>	<u>8.024¢ per kWh for all kWh</u>
<u>Summer Off Peak</u>	<u>4.775¢ per kWh for all kWh</u>
<u>Non-Capacity Energy (October – May)</u>	
<u>Non-Summer On Peak</u>	<u>5.547¢ per kWh for all kWh</u>
<u>Non-Summer Off Peak</u>	<u>4.775¢ per kWh for all kWh</u>

<u>Non-Capacity Voltage Level Discount:</u>	
	<u>0.205¢ per kWh at transmission level</u>
	<u>0.092¢ per kWh at subtransmission level</u>

Delivery Charges:

<u>Primary Service Charge:</u>	<u>\$70 per month</u>
<u>Subtransmission and Transmission Service Charge:</u>	<u>\$375 per month</u>

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(Continued from Sheet No. D-48.11)

RATE SCHEDULE NO. D14

PRIMARY TOU

Distribution Charges:

For primary service (less than 24 kV) \$6.66 per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) \$1.82 per kW of maximum demand.

For service at transmission voltage (120 kV and above) \$0.99 per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Capacity Energy (June – September)

Summer On Peak 2.649¢ per kWh for all kWh

Summer Off Peak 1.576¢ per kWh for all kWh

Capacity Energy (October – May)

Non-Summer On Peak 1.831¢ per kWh for all kWh

Non-Summer Off Peak 1.576¢ per kWh for all kWh

Capacity Voltage Level Discount:

0.068¢ per kWh at transmission level

0.030¢ per kWh at subtransmission level

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C5.8.

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24 kV) \$6.66 per kW of maximum demand.

For service at subtransmission voltage (24 to 41.6 kV) \$1.82 per kW of maximum demand.

For service at transmission voltage (120 kV and above) \$0.99 per kW of maximum demand.

Substation Credit: Available to customers where service at sub-transmission voltage level (24 to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$0.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of 0.040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

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RATE SCHEDULE NO. D14

PRIMARY TOU

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

DEFINITION OF CUSTOMER VOLTAGE LEVEL: See Section C13.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of contract capacity. This clause is applicable to each voltage level served.

MINIMUM CHARGE: All applicable demand charges plus the service charge and any applicable per meter per month surcharges.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

POWER FACTOR CLAUSE:

Full Service Customers:

The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Any power factor less than 70% will not be permitted and the customer will be required to install at his own expense such corrective equipment as may be necessary to improve power factor. A penalty will be applied to the total amount of the monthly billing for electric energy for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The Power Factor Clause shall not be applied to the on-peak billing demand ratchet nor to the minimum contract demand, but will be applied to metered quantities.

Retail Access Service Customers:

A power factor of less than 70% is not permitted and necessary corrective equipment must be installed by the Customer to correct to a minimum level of 70%. Power factor and excess Reactive Demand charges will be calculated at each Customer location at the time of the Location's single highest 30-minute integrated kW reading of the Interval Demand Meter during the on-peak hours of the billing period, which are those hours from 7 a.m. until 11 p.m. consistent with the ITC Open Access Transmission Tariff. Excess Reactive Demand is any Reactive Demand resulting from operations below 80% power factor. A monthly charge of \$3.50/kVAR will be applied to excess Reactive Demand.

SPECIAL TERMS AND CONDITIONS: The contract capacity however established shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a specific reduction in connected load.

Customer-owned equipment must be operated so that voltage fluctuations on the primary distribution system of the Company shall not exceed permissible limits.

Customers will be permitted to transfer from this rate to a secondary commercial rate, provided they can meet the availability requirements, if the load characteristic changes sufficiently so that the customer would benefit by the change for the foreseeable future even though metering was continued at primary voltage. Frequent changes, however, from one rate to another for a period less than one full year will not be permitted in accordance with Section C4.4 - Choice of Rates.

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RATE SCHEDULE NO. D14

PRIMARY TOU

SPECIAL TERMS AND CONDITIONS (Contd.)

For example, during the period that a building is under construction, primary service may be supplied and metered at primary voltage and billed on a secondary rate while the building is under the jurisdiction of the contractor.

Also, for the convenience of the utility, service to a large school complex or a high rise building where, as a matter of design, primary voltage is furnished with Company owned transformers at remote locations fed by customer owned primary cables, the account can be billed on a secondary rate though metered at one central primary voltage location at or near the termination of the utility-owned cables.

At the option of the Company, service may be supplied at the primary voltage and metered at a secondary voltage when the customer transfers from a secondary rate. For loads metered at a secondary voltage (less than 600V), all measured quantities shall be increased by 2%.

CONTRACT TERM: For new primary installations over 1000 kW the term is for not less than five years, extending thereafter from month-to-month until terminated by mutual consent or on twelve months' written notice by either party, which may be given at any time after the end of the fourth year. For new primary installations of 1000 kW or less and for new customers at existing installations, the term is for three years which under special circumstances may be increased or reduced at the discretion of the Company, extending thereafter from month-to-month until terminated by mutual consent or on one month written notice by either party. Where special services are required, the term will be as specified in the applicable contract rider.

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

CONTRACT TERM: Minimum 5 year term. Upon expiration of the initial term shall continue on a month-to-month basis until terminated by mutual written consent of the parties or by either party with thirty (30) days prior written notice to the other party. Any conversion, relocation and/or removal of existing street lighting facilities at the customer's request, including those removals necessitated by termination of service, must be paid for by the customer. The detailed provisions and schedule of charges, which may include the remaining value of the existing facilities, will be quoted upon request. The Company shall not withdraw service, and the municipality shall not substitute another source of service in whole or in part, without twelve months' written notice to the other party.

Option I: Company Owned Street Lighting System

Where new installations require an investment in excess of an investment allowance, Option I is available only to customers who make a contribution in aid of construction equal to the amount by which the investment exceeds three times the annual revenue at the prevailing rate at the time of installation. (Effective January 1, 1991, the investment amount will be limited to direct cost. Effective January 1, 1992, the investment amount will include full cost.)

As an alternative, where the required contribution exceeds \$10,000, upon agreement of the customer and the Company, the customer will pay an additional annual charge of the Company's weighted average cost of capital (~~6.92~~7.37%) times the contribution amount in lieu of the cash contribution.

For new underground-fed installations of 5 lights or more after May 1, 2019, which require investment in excess of three times the annual revenue at the prevailing rate at the time of installation, the customer may elect to pay a post charge for each increment of \$1,000 investment required above three times the annual revenue.

DE-ENERGIZED LIGHTS: Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 60% of the regular yearly rates. A \$35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.

DUSK TO MIDNIGHT SERVICE: For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours of use will be applied. One control per circuit or luminaire will be provided.

EXPERIMENTAL PROGRAMMABLE PHOTOCCELL SERVICE: Customers may elect to place luminaires on photocells that are programmable to turn off lights at pre-determined times during the night. A distribution discount of 1.060¢ per nominal lamp size wattage per month and a 50% reduction in the average monthly hours on use will be applied.

MONTHLY RATES OPTION I: Overhead Municipal Street Lighting (All-night service).

Power Supply Charges:

Capacity Energy Charge: 0.00¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~4.64~~4.6¢ per kWh for all kWh

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

Luminaire Charges:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
100 W	Mercury Vapor	~~\$27.80~~ ^{5.34}	120	350	\$0.0466	~~\$1.96~~ ⁸⁷	~~\$29.76~~ ^{7.24}
175 W	Mercury Vapor	~~\$34.43~~ ^{1.35}	210	350	\$0.0466	~~\$3.43~~ ²⁸	~~\$37.86~~ ^{4.63}
250 W	Mercury Vapor	~~\$41.13~~ ^{7.52}	300	350	\$0.0466	~~\$4.90~~ ^{206.8}	~~\$46.02~~ ^{2.20}
400 W	Mercury Vapor	~~\$54.52~~ ^{49.56}	450	350	\$0.0466	~~\$7.35~~ ⁴⁰²	~~\$61.86~~ ^{56.58}
1,000 W	Mercury Vapor	~~\$116.02~~ ^{205.40}	1060	350	\$0.0466	~~\$17.31~~ ^{216.53}	~~\$133.32~~ ^{21.93}
70 W	High Pressure Sodium	~~\$20.69~~ ^{18.86}	95	350	\$0.0466	~~\$1.55~~ ⁴⁸	~~\$22.24~~ ^{0.34}
100 W	High Pressure Sodium	~~\$23.64~~ ^{1.53}	135	350	\$0.0466	~~\$2.20~~ ¹⁴	~~\$25.84~~ ^{1.63}
150 W	High Pressure Sodium	~~\$28.08~~ ^{5.87}	200	350	\$0.0466	~~\$3.27~~ ²¹²	~~\$31.35~~ ^{528.99}
250 W	High Pressure Sodium	~~\$36.97~~ ^{2.61}	305	350	\$0.0466	~~\$4.98~~ ²⁶	~~\$41.95~~ ^{538.36}
360 W	High Pressure Sodium	~~\$43.17~~ ^{2.05}	418	350	\$0.0466	~~\$6.82~~ ⁵²	~~\$49.99~~ ^{5.57}
400 W	High Pressure Sodium	~~\$45.42~~ ^{2.2}	465	350	\$0.0466	~~\$7.59~~ ²⁵	~~\$53.01~~ ^{12.35}
1,000 W	High Pressure Sodium	~~\$79.23~~ ^{82.64}	1100	350	\$0.0466	~~\$17.96~~ ¹⁶	~~\$97.19~~ ^{90.80}
70 W	Metal Halide	~~\$26.83~~ ^{4.48}	85	350	\$0.0466	~~\$1.39~~ ²	~~\$28.22~~ ^{5.81}
100 W	Metal Halide	~~\$27.24~~ ^{4.83}	120	350	\$0.0466	~~\$1.96~~ ⁸⁷	~~\$29.20~~ ^{6.70}
150 W	Metal Halide	~~\$33.11~~ ^{0.17}	180	350	\$0.0466	~~\$2.94~~ ⁸¹	~~\$36.05~~ ^{2.97}
175 W	Metal Halide	~~\$36.05~~ ^{2.83}	210	350	\$0.0466	~~\$3.43~~ ²⁸	~~\$39.48~~ ^{6.11}
250 W	Metal Halide	~~\$44.87~~ ^{0.84}	300	350	\$0.0466	~~\$4.90~~ ⁶⁸	~~\$49.77~~ ^{5.52}
320 W	Metal Halide	~~\$52.42~~ ^{247.70}	365	350	\$0.0466	~~\$5.96~~ ⁶⁰	~~\$58.38~~ ^{3.39}
400 W	Metal Halide	~~\$61.05~~ ^{55.52}	460	350	\$0.0466	~~\$7.51~~ ¹²	~~\$68.56~~ ^{2.71}
1,000 W	Metal Halide	~~\$126.11~~ ^{14.64}	1050	350	\$0.0466	~~\$17.14~~ ^{46.38}	~~\$143.25~~ ^{21.02}
20 - 29 W	LED	~~\$15.50~~ ^{0.1}	25	350	\$0.0466	~~\$0.41~~ ²⁰	~~\$15.90~~ ^{0.30}
30 - 39 W	LED	~~\$16.78~~ ^{0.5}	35	350	\$0.0466	~~\$0.57~~ ⁵	~~\$17.36~~ ^{0.20}
40 - 49 W	LED	~~\$18.07~~ ^{2.29}	45	350	\$0.0466	~~\$0.73~~ ⁹	~~\$18.81~~ ^{0.99}
50 - 59 W	LED	~~\$19.36~~ ^{8.12}	55	350	\$0.0466	~~\$0.90~~ ⁶⁶	~~\$20.26~~ ^{18.98}
60 - 69 W	LED	~~\$20.66~~ ^{19.29}	65	350	\$0.0466	~~\$1.06~~ ⁴	~~\$21.72~~ ^{0.30}
70 - 79 W	LED	~~\$21.96~~ ^{0.46}	75	350	\$0.0466	~~\$1.22~~ ¹⁷	~~\$23.19~~ ^{1.63}
80 - 89 W	LED	~~\$23.26~~ ^{1.63}	85	350	\$0.0466	~~\$1.39~~ ²	~~\$24.65~~ ^{2.95}
90 - 99 W	LED	~~\$24.56~~ ^{2.80}	95	350	\$0.0466	~~\$1.55~~ ⁴⁸	~~\$26.11~~ ^{4.28}
100 - 109 W	LED	~~\$25.86~~ ^{3.97}	105	350	\$0.0466	~~\$1.71~~ ⁶⁴	~~\$27.58~~ ^{5.61}
110 - 119 W	LED	~~\$27.16~~ ^{5.14}	115	350	\$0.0466	~~\$1.88~~ ²⁹	~~\$29.04~~ ^{6.93}
120 - 129 W	LED	~~\$28.46~~ ^{6.31}	125	350	\$0.0466	~~\$2.04~~ ^{1.95}	~~\$30.50~~ ^{28.26}
130 - 139 W	LED	~~\$29.76~~ ^{7.40}	135	350	\$0.0466	~~\$2.20~~ ¹¹	~~\$31.97~~ ^{20.50}
140 - 149 W	LED	~~\$30.88~~ ^{28.27}	145	350	\$0.0466	~~\$2.37~~ ²⁶	~~\$33.25~~ ^{0.53}
150 - 159 W	LED	~~\$31.23~~ ^{29.13}	155	350	\$0.0466	~~\$2.53~~ ⁴²	~~\$33.76~~ ^{1.55}
160 - 169 W	LED	~~\$32.33~~ ^{30.00}	165	350	\$0.0466	~~\$2.69~~ ⁵⁷	~~\$35.02~~ ^{2.58}

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
170 - 179 W	LED	~~\$33,420.86~~	175	350	\$0.04646	~~\$2,862.3~~	~~\$36,283.59~~
180 - 189 W	LED	~~\$34,511.73~~	185	350	\$0.04646	~~\$3,022.89~~	~~\$37,534.61~~
190 - 199 W	LED	~~\$35,612.59~~	195	350	\$0.04646	~~\$3,184.4~~	~~\$38,795.63~~
200 - 209 W	LED	~~\$36,702.46~~	205	350	\$0.04646	~~\$3,350.9~~	~~\$40,056.66~~
210 - 219 W	LED	~~\$37,684.32~~	215	350	\$0.04646	~~\$3,525.5~~	~~\$41,192.67~~
220 - 229 W	LED	~~\$38,014.61~~	225	350	\$0.04646	~~\$3,675.1~~	~~\$41,684.13~~
230 - 239 W	LED	~~\$38,334.90~~	235	350	\$0.04646	~~\$3,846.7~~	~~\$42,1748.56~~
240 - 249 W	LED	~~\$39,265.74~~	245	350	\$0.04646	~~\$4,003.82~~	~~\$43,2639.56~~
250 - 259 W	LED	~~\$40,1846.58~~	255	350	\$0.04646	~~\$4,163.98~~	~~\$44,350.55~~
260 - 269 W	LED	~~\$41,1032.41~~	265	350	\$0.04646	~~\$4,331.3~~	~~\$45,431.55~~
270 - 279 W	LED	~~\$42,0138.25~~	275	350	\$0.04646	~~\$4,429~~	~~\$46,522.54~~
280 - 289 W	LED	~~\$42,9530.09~~	285	350	\$0.04646	~~\$4,651.4~~	~~\$47,602.54~~
290 - 299 W	LED	~~\$43,8720.93~~	295	350	\$0.04646	~~\$4,826.0~~	~~\$48,694.52~~
300 - 309 W	LED	~~\$44,800.77~~	305	350	\$0.04646	~~\$4,982.6~~	~~\$49,785.52~~
310 - 319 W	LED	~~\$45,721.61~~	315	350	\$0.04646	~~\$5,144.91~~	~~\$50,8746.52~~
320 - 329 W	LED	~~\$46,652.45~~	325	350	\$0.04646	~~\$5,310.7~~	~~\$51,9642.52~~
330 - 339 W	LED	~~\$47,583.29~~	335	350	\$0.04646	~~\$5,472.2~~	~~\$53,0548.51~~
340 - 349 W	LED	~~\$48,504.12~~	345	350	\$0.04646	~~\$5,638.8~~	~~\$54,1449.51~~
350 - 359 W	LED	~~\$49,434.96~~	355	350	\$0.04646	~~\$5,805.4~~	~~\$55,2349.50~~
360 - 369 W	LED	~~\$50,3545.80~~	365	350	\$0.04646	~~\$5,966.9~~	~~\$56,314.49~~
370 - 379 W	LED	~~\$51,2846.64~~	375	350	\$0.04646	~~\$6,125.85~~	~~\$57,402.49~~
380 - 389 W	LED	~~\$52,2147.48~~	385	350	\$0.04646	~~\$6,290.0~~	~~\$58,492.48~~
390 - 399 W	LED	~~\$53,1348.32~~	395	350	\$0.04646	~~\$6,451.6~~	~~\$59,584.48~~

Multiple Lamps on a Single Pole

- For each additional luminaire added to the same pole, reduce rate per lamp per year on the added luminaire \$12.24.

The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, the luminaire will be converted to LED.

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

Option I: Company Owned Street Lighting System (Contd.)

MONTHLY RATES OPTION I: Ornamental Underground Municipal Street Lighting for Lamp Spacing up to 120 Feet of Street (All-night service).

Power Supply Charges:

Capacity Energy Charge: 0.00¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~4.646¢~~ per kWh for all kWh

Luminaire Charges:

(a) Nominal Lamp Size	(b) Type of Service	(c) Distribution Charge per Lamp per Month	(d) System Wattage	(e) Average Monthly Hours (4200/12)	(f) Energy Charge	(g) Average Energy Cost per Month (d*e*f/1000)	(h) Average Monthly Cost
100 W	Mercury Vapor	~~\$32.408~~	120	350	~~\$0.04646~~	~~\$1.9687~~	\$34.36
175 W	Mercury Vapor	~~\$38.147-64~~	210	350	~~\$0.04646~~	~~\$3.4328~~	~~\$41.570-91~~
250 W	Mercury Vapor	~~\$46.515-55~~	300	350	~~\$0.04646~~	~~\$4.9068~~	~~\$51.410-23~~
400 W	Mercury Vapor	~~\$59.677-87~~	450	350	~~\$0.04646~~	~~\$7.3502~~	~~\$67.024-89~~
1,000 W	Mercury Vapor	~~\$123.2618-04~~	1060	350	~~\$0.04646~~	~~\$17.316-53~~	~~\$140.5634-58~~
70 W	High Pressure Sodium	~~\$24.707~~	95	350	~~\$0.04646~~	~~\$1.5548~~	~~\$26.265~~
100 W	High Pressure Sodium	~~\$27.988-06~~	135	350	~~\$0.04646~~	~~\$2.2011~~	~~\$30.197~~
150 W	High Pressure Sodium	~~\$31.7504~~	200	350	~~\$0.04646~~	~~\$3.2712~~	~~\$35.024-16~~
250 W	High Pressure Sodium	~~\$39.848-42~~	305	350	~~\$0.04646~~	~~\$4.9876~~	~~\$44.823-17~~
360 W	High Pressure Sodium	~~\$48.406-06~~	418	350	~~\$0.04646~~	~~\$6.8252~~	~~\$55.222-58~~
400 W	High Pressure Sodium	~~\$51.5148-83~~	465	350	~~\$0.04646~~	~~\$7.5925~~	~~\$59.106-09~~
1,000 W	High Pressure Sodium	~~\$102.4192-93~~	1100	350	~~\$0.04646~~	~~\$17.9616~~	~~\$120.3710-08~~
70 W	Metal Halide	~~\$34.306~~	85	350	~~\$0.04646~~	~~\$1.393~~	~~\$35.698~~
100 W	Metal Halide	~~\$36.2937~~	120	350	~~\$0.04646~~	~~\$1.9687~~	~~\$38.25~~
150 W	Metal Halide	~~\$43.920-05~~	180	350	~~\$0.04646~~	~~\$2.9481~~	~~\$46.862-86~~
175 W	Metal Halide	~~\$40.3752~~	210	350	~~\$0.04646~~	~~\$3.4328~~	~~\$43.8079~~
250 W	Metal Halide	~~\$48.4813~~	300	350	~~\$0.04646~~	~~\$4.9068~~	~~\$53.372-81~~

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
320 W	Metal Halide	~~\$55.79~~ 3.97	365	350	~~\$0.046~~ 46	~~\$5.96~~ 69	~~\$61.75~~ 59.66
400 W	Metal Halide	~~\$64.15~~ 9.63	460	350	~~\$0.046~~ 46	~~\$7.51~~ 17	~~\$71.66~~ 67.80
1,000 W	Metal Halide	~~\$126.86~~ 10.60	1050	350	~~\$0.046~~ 46	~~\$17.14~~ 6.38	~~\$144.00~~ 26.98
20 - 29 W	LED	~~\$20.47~~ 50	25	350	~~\$0.046~~ 46	~~\$0.41~~ 39	~~\$20.88~~ 9
30 - 39 W	LED	~~\$21.21~~ 3	35	350	~~\$0.046~~ 46	~~\$0.57~~ 5	~~\$21.78~~
40 - 49 W	LED	~~\$21.94~~ 7	45	350	~~\$0.046~~ 46	~~\$0.73~~ 0	~~\$22.67~~
50 - 59 W	LED	~~\$22.65~~ 9	55	350	~~\$0.046~~ 46	~~\$0.90~~ 86	~~\$23.55~~
60 - 69 W	LED	~~\$23.45~~ 42	65	350	~~\$0.046~~ 46	~~\$1.06~~ 1	~~\$24.51~~ 44
70 - 79 W	LED	~~\$24.45~~ 15	75	350	~~\$0.046~~ 46	~~\$1.22~~ 17	~~\$25.67~~ 32
80 - 89 W	LED	~~\$25.44~~ 1.88	85	350	~~\$0.046~~ 46	~~\$1.39~~ 3	~~\$26.83~~ 6.21
90 - 99 W	LED	~~\$26.45~~ 5.78	95	350	~~\$0.046~~ 46	~~\$1.55~~ 48	~~\$28.00~~ 7.26
100 - 109 W	LED	~~\$27.45~~ 6.68	105	350	~~\$0.046~~ 46	~~\$1.71~~ 64	~~\$29.16~~ 8.32
110 - 119 W	LED	~~\$28.45~~ 7.58	115	350	~~\$0.046~~ 46	~~\$1.88~~ 79	~~\$30.33~~ 29.37
120 - 129 W	LED	~~\$29.45~~ 28.48	125	350	~~\$0.046~~ 46	~~\$2.04~~ 1.95	~~\$31.49~~ 0.43
130 - 139 W	LED	~~\$30.45~~ 29.38	135	350	~~\$0.046~~ 46	~~\$2.20~~ 11	~~\$32.66~~ 1.48
140 - 149 W	LED	~~\$31.36~~ 30.18	145	350	~~\$0.046~~ 46	~~\$2.37~~ 26	~~\$33.72~~ 2.44
150 - 159 W	LED	~~\$32.26~~ 0.99	155	350	~~\$0.046~~ 46	~~\$2.53~~ 42	~~\$34.79~~ 3.40
160 - 169 W	LED	~~\$33.16~~ 1.79	165	350	~~\$0.046~~ 46	~~\$2.69~~ 57	~~\$35.85~~ 4.36
170 - 179 W	LED	~~\$34.06~~ 2.59	175	350	~~\$0.046~~ 46	~~\$2.86~~ 73	~~\$36.92~~ 5.32
180 - 189 W	LED	~~\$34.96~~ 3.40	185	350	~~\$0.046~~ 46	~~\$3.02~~ 2.89	~~\$37.98~~ 6.28
190 - 199 W	LED	~~\$35.86~~ 4.20	195	350	~~\$0.046~~ 46	~~\$3.18~~ 04	~~\$39.04~~ 7.24
200 - 209 W	LED	~~\$36.76~~ 5.01	205	350	~~\$0.046~~ 46	~~\$3.35~~ 20	~~\$40.11~~ 38.20
210 - 219 W	LED	~~\$37.66~~ 5.81	215	350	~~\$0.046~~ 46	~~\$3.51~~ 35	~~\$41.17~~ 39.16
220 - 229 W	LED	~~\$38.56~~ 6.61	225	350	~~\$0.046~~ 46	~~\$3.67~~ 51	~~\$42.24~~ 0.12

(Continued on Sheet No. D-51.02)

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(Continued from Sheet No. D-51.01)

RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

Luminaire Charges (Contd.):

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Nominal Lamp Size	Type of Service	Distribution Charge per Lamp per Month	System Wattage	Average Monthly Hours (4200/12)	Energy Charge	Average Energy Cost per Month (d*e*f/1000)	Average Monthly Cost
230 - 239 W	LED	\$39.46 ~~7.42~~	235	350	\$0.04 ~~646~~	\$3.84 ~~67~~	\$43.30 ~~1.08~~
240 - 249 W	LED	\$40.37 ~~38.22~~	245	350	\$0.04 ~~646~~	\$4.00 ~~3.82~~	\$44.37 ~~2.04~~
250 - 259 W	LED	\$41.27 ~~39.02~~	255	350	\$0.04 ~~646~~	\$4.16 ~~3.98~~	\$45.43 ~~4.00~~
260 - 269 W	LED	\$42.17 ~~39.83~~	265	350	\$0.04 ~~646~~	\$4.33 ~~4.13~~	\$46.49 ~~3.96~~
270 - 279 W	LED	\$43.07 ~~40.63~~	275	350	\$0.04 ~~646~~	\$4.49 ~~29~~	\$47.56 ~~4.92~~
280 - 289 W	LED	\$43.97 ~~41.44~~	285	350	\$0.04 ~~646~~	\$4.65 ~~44~~	\$48.62 ~~5.88~~
290 - 299 W	LED	\$44.87 ~~42.24~~	295	350	\$0.04 ~~646~~	\$4.82 ~~60~~	\$49.69 ~~6.84~~
300 - 309 W	LED	\$45.77 ~~43.04~~	305	350	\$0.04 ~~646~~	\$4.98 ~~76~~	\$50.75 ~~47.80~~
310 - 319 W	LED	\$46.67 ~~43.85~~	315	350	\$0.04 ~~646~~	\$5.14 ~~4.91~~	\$51.81 ~~48.76~~
320 - 329 W	LED	\$47.57 ~~44.65~~	325	350	\$0.04 ~~646~~	\$5.31 ~~107~~	\$52.88 ~~49.72~~
330 - 339 W	LED	\$48.47 ~~45.46~~	335	350	\$0.04 ~~646~~	\$5.47 ~~22~~	\$53.94 ~~40.68~~
340 - 349 W	LED	\$49.37 ~~46.26~~	345	350	\$0.04 ~~646~~	\$5.63 ~~38~~	\$55.01 ~~41.64~~
350 - 359 W	LED	\$50.28 ~~47.06~~	355	350	\$0.04 ~~646~~	\$5.80 ~~54~~	\$56.07 ~~42.60~~
360 - 369 W	LED	\$51.18 ~~47.87~~	365	350	\$0.04 ~~646~~	\$5.96 ~~69~~	\$57.14 ~~43.56~~
370 - 379 W	LED	\$52.08 ~~48.67~~	375	350	\$0.04 ~~646~~	\$6.12 ~~5.85~~	\$58.20 ~~44.52~~
380 - 389 W	LED	\$52.98 ~~49.47~~	385	350	\$0.04 ~~646~~	\$6.29 ~~00~~	\$59.26 ~~45.48~~
390 - 399 W	LED	\$53.88 ~~50.28~~	395	350	\$0.04 ~~646~~	\$6.45 ~~16~~	\$60.33 ~~46.44~~

Long Span

- For lamp spacing over 120 feet up to 325 feet on the same side of street, add to rate per lamp per year..... \$24.48

Semi-Ornamental

- For Semi-Ornamental Systems which employ Ornamental Post Units served from overhead conductors, where such construction is practical, reduce rate per luminaire per year \$21.48

Post Charge

- For each increment of \$1,000 of investment which exceeds three times the annual revenue at the prevailing rate at the time of installation, add to rate per year..... \$84.96~~2.56~~

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

Multiple Luminaires on a Single Pole

- For additional luminaires added to the same pole, a reduced rate per luminaire per year on the added luminaire.
Ornamental \$97.92
Ornamental-Lamp spacing over 120 feet \$122.40
Semi-Ornamental \$76.56

OPTION II: Street Equipment Owned by Municipality

MONTHLY RATES OPTION II: Overhead and Underground Ornamental Municipality Owned Street Lighting (All-night service).

Power Supply Charges:

Capacity Energy Charge: 0.00¢ per kWh for all kWh

Non-Capacity Energy Charge: 4.64¢ per kWh for all kWh

(a) Nominal Lamp Size	(b) Type of Service	(c) Distribution Charge per Lamp per Month	(d) System Wattage	(e) Average Monthly Hours (4200/12)	(f) Energy Charge	(g) Average Energy Cost per Month (d*e*f/1000)	(h) Average Monthly Cost
175 W	Mercury Vapor	~~\$9.94~~ 7.86	210	350	\$0.04646	~~\$3.43~~ 2.8	~~\$13.37~~ 1.14
250 W	Mercury Vapor	~~\$14.20~~ 1.23	300	350	\$0.04646	~~\$4.90~~ 6.8	~~\$19.10~~ 5.91
400 W	Mercury Vapor	~~\$22.72~~ 17.97	450	350	\$0.04646	~~\$7.35~~ 9.2	~~\$30.07~~ 24.99
1,000 W	Mercury Vapor	~~\$56.81~~ 44.93	1060	350	\$0.04646	~~\$17.31~~ 6.53	~~\$74.11~~ 61.46
70 W	High Pressure Sodium	~~\$6.96~~ 5.36	95	350	\$0.04646	~~\$1.55~~ 4.8	~~\$8.52~~ 6.85
100 W	High Pressure Sodium	~~\$8.46~~ 6.56	135	350	\$0.04646	~~\$2.20~~ 11	~~\$10.66~~ 8.67
250 W	High Pressure Sodium	~~\$15.94~~ 2.55	305	350	\$0.04646	~~\$4.98~~ 7.6	~~\$20.92~~ 17.30
360 W	High Pressure Sodium	~~\$21.43~~ 16.94	418	350	\$0.04646	~~\$6.82~~ 5.2	~~\$28.25~~ 3.45
400 W	High Pressure Sodium	~~\$23.42~~ 18.53	465	350	\$0.04646	~~\$7.59~~ 2.5	~~\$31.02~~ 25.78
1,000 W	High Pressure Sodium	~~\$53.35~~ 42.47	1100	350	\$0.04646	~~\$17.96~~ 1.6	~~\$71.31~~ 59.63

- The Energy Policy Act of 2005 states that no Mercury Vapor lamp ballasts may be manufactured or imported after January 1, 2008. As a result, effective January 1, 2008, new Mercury Vapor lamps will no longer be available. Customers with existing Mercury Vapor lamp ballasts will continue to receive service until those luminaires fail. At that time, customers will be given the option of switching to High Pressure Sodium, Metal Halide, LED or retiring the Luminaire.

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

- **DE-ENERGIZED LIGHTS:** Customers may elect to have any or all luminaires served under this rate disconnected. The charge per luminaire per year, payable in equal monthly installments, shall be 10% of the above yearly rates. A \$35.00 charge per luminaire will be made at the time of de-energization and at the time of re-energization.
- **DUSK TO MIDNIGHT SERVICE:** For service to parking lots from dusk to approximately twelve o'clock midnight E.S.T., a discount of 1.060¢ per nominal watt per month will be applied. One control per circuit will be provided.

OPTION III: Municipally Owned and Maintained Street Lighting System (Unmetered)

HOURS OF SERVICE: For circuits controlled by automatic timing devices, one-half hour after sunset until one-half hour before sunrise. For circuits controlled by photo-sensitive devices, dusk to dawn for approximately 4,200 hours per year.

RATES: Where the municipality owns, operates, cleans and renews the lamps, and the Company's service is confined solely to the supply of electricity from dusk to dawn, the monthly charge of said service shall be a power supply capacity energy charge of 0.00¢ per kilowatthour, a power supply non-capacity charge of ~~4.466¢~~ per kilowatthour and a distribution charge of ~~13.360-88¢~~ per kilowatthour. If it is necessary for the Company to install facilities to provide service for the lamps, the customer will reimburse the Company for these costs. Contract Rider No. 2 charges will also apply.

OPTION III: Municipally Owned and Maintained Street Lighting System (Controlled/Metered)

AVAILABILITY OF SERVICE: Available to governmental agencies desiring controlled nighttime service for primary or secondary voltage energy-only street lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires served under any of the Company's other street lighting rates shall not be intermixed with luminaires serviced under this street lighting rate. This rate is not available for resale purposes. Service is governed by the Company's Standard Rules and Regulations.

KIND OF SERVICE:

Secondary Voltage Service: Alternating current, 60 hertz, single-phase 120/240 nominal volt service for a minimum of ten luminaires located within a clearly defined area. Except for control equipment, the customer will furnish, install, own and maintain all equipment comprising the street lighting system up to the point of attachment with the Company's distribution system. The Company will connect the customer's equipment to the Company's lines and supply the energy for operation. All of the customer's equipment will be subject to the Company's review.

Primary Voltage Service: Alternating current, 60 hertz, single-phase or three-phase, primary voltage service for actual demands of not less than 100 kW at each point of delivery. The particular nature of the voltage shall be determined by the Company. The customer will furnish, install, own and maintain all equipment comprising the street lighting system, including control equipment, up to the point of attachment with the Company's distribution system. The Company will supply the energy for operation of the customer's street lighting system.

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RATE SCHEDULE NO. E1 (Contd.)

MUNICIPAL STREET LIGHTING RATE

**Primary and Secondary Energy
Full Service Customers:**

Power Supply Charge:

Capacity Dusk to Midnight: ~~7.8293.023~~¢ per kWh

Capacity Energy Charge: ~~1.7920.692~~¢ per kWh for all kWh

Non-Capacity Energy Charge: ~~4.0454.892~~¢ per kWh for all kWh

Delivery System Charge:

5.288¢ per kWh based on the capacity requirements in kilowatts of the equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Retail Access Service Customers:

Power Supply Charges for Retail Access Service Customers taking Utility Capacity Service from DTE:

Capacity Energy Charge: ~~1.7920.692~~¢ per kWh for all kWh

Delivery System Charge:

~~6.1565.288~~¢ per kWh based on the capacity requirements in kilowatts of the equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption and the total annual kWh consumption.

At the Company's option, service may be metered and the metered kWh will be the basis for billing. Capacity requirements of lighting equipment shall be determined by the Company from manufacturer specifications, but the Company maintains the right to test such capacity requirements from time to time. In the event that Company tests show capacity requirements other than those indicated in manufacturer specifications, the capacity requirements indicated by Company tests will be used. The customer shall not change the capacity requirements of its equipment without first notifying the Company in writing.

BILLING: Billing will be on a monthly basis.

SURCHARGES AND CREDITS: As approved by the Commission. Power Supply Charges are subject to Section C8.5. Delivery Charges are subject to Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The contract minimum.

CONTRACT TERM: Contracts will be taken for a minimum of two years, extending thereafter from year to year until terminated by mutual consent or upon 12 months' written notice by either party.

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RATE SCHEDULE NO. E2

TRAFFIC AND SIGNAL LIGHTS

AVAILABILITY OF SERVICE: Available to municipalities or other public authorities, hereinafter referred to as customer, operating lights for traffic regulation or signal lights on streets, highways, airports or water routes, as distinguished from street lighting. Customers desiring service under Rate Schedule No. E2 are free to determine the appropriate light source for their application including incumbent and emerging technologies (including LEDs). Customers must supply adequate documentation of the wattage of the light source that will be subject to the approval of the Company.

HOURS OF SERVICE: 24 hours.

CURRENT, PHASE AND VOLTAGE: Alternating current, single-phase, at 120 volts two-wire.

SERVICE CONNECTIONS: The customer is to furnish and maintain all necessary wiring and equipment, including lamps and lamp replacements, or reimburse the Company therefore, except that the Company will furnish, install and maintain such span poles and messenger cable as may be needed to support the traffic or signal lights of the overhead type. Connections are to be brought to the Company's underground and overhead lighting mains by the customer as directed by the Company, and the final connection to the Company's main is to be made by the Company.

Conversion and/or relocation of existing facilities must be paid for by the customer, except when initiated by the Company. The detailed provisions and schedule of such charges will be quoted upon request.

RATES: Distribution charge of ~~3.042-63¢~~, capacity energy charge of ~~1.440-56¢~~ and non-capacity energy charge of ~~5.195-83¢~~ per month per kilowatthour of the total connected traffic light or signal light load in service for each customer.

Total connected wattage will be reckoned as of the fifteenth of the month. Lamps removed from service before the fifteenth or placed in service on or after the fifteenth will be omitted from the reckoning; conversely, lamps placed in service on or before the fifteenth of the month or removed from service after the fifteenth of the month will be reckoned for a full month. Lamps operated cyclically, on and off, will be reckoned at one-half wattage and billed for a full month. No such reduction of reckoned wattage will be allowed for lamps in service but turned off during certain hours of the day.

The Company may, at its option, install meters and apply a standard metered rate schedule applicable to the service.

SURCHARGES AND CREDITS: As approved by the Commission. See Sections C8.5 and C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: \$3.00 per customer per month.

CONTRACT TERM: Open order on a month-to-month basis. However, the Company shall not withdraw service, and the customer shall not substitute another source of service in whole or in part, without twelve months' written notice to the other party.

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(Continued from Sheet No. D-57.00)

STANDARD CONTRACT RIDER NO. 1.1 (Contd.)

ALTERNATIVE ELECTRIC METAL MELTING

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)

1.789~~0.706~~¢ per kWh for the first 100 hours use of maximum demand

0.676~~0.267~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

1.330~~0.525~~¢ per kWh for the first 100 hours use of maximum demand

0.484~~0.191~~¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)

1.297~~0.512~~¢ per kWh for the first 100 hours use of maximum demand

0.451~~0.178~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

1.100~~0.434~~¢ per kWh for the first 100 hours use of maximum demand

0.365~~0.144~~¢ per kWh for the excess

Non-Capacity

Energy Charge: 4.892~~5.251~~¢ per kWh for all kWh

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)

6.156~~5.288~~¢ per kWh for the first 100 hours use of maximum demand

6.156~~5.288~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

2.015~~1.832~~¢ per kWh for the first 100 hours use of maximum demand

2.015~~1.832~~¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)

0.532~~0.677~~¢ per kWh for the first 100 hours use of maximum demand

0.532~~0.677~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

0.600~~0.274~~¢ per kWh for the first 100 hours use of maximum demand

0.600~~0.274~~¢ per kWh for the excess

(Continued on Sheet No. D-59.00)

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STANDARD CONTRACT RIDER NO. 1.1 (Contd.)

ALTERNATIVE ELECTRIC METAL MELTING

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8

Retail Access Service Customers:

Capacity (Only applicable to Retail access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)

1.789~~0.706~~¢ per kWh for the first 100 hours use of maximum demand

0.676~~0.267~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

1.330~~0.525~~¢ per kWh for the first 100 hours use of maximum demand

0.484~~0.191~~¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)

1.297~~0.512~~¢ per kWh for the first 100 hours use of maximum demand

0.451~~0.178~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

1.100~~0.434~~¢ per kWh for the first 100 hours use of maximum demand

0.365~~0.144~~¢ per kWh for the excess

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)

6.156~~5.288~~¢ per kWh for the first 100 hours use of maximum demand

6.156~~5.288~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

2.015~~1.832~~¢ per kWh for the first 100 hours use of maximum demand

2.015~~1.832~~¢ per kWh for the excess

(Continued from Sheet No. D-60.00)

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STANDARD CONTRACT RIDER NO. 1.1 (Contd.)

ALTERNATIVE ELECTRIC METAL MELTING

For service at subtransmission voltage level (24 kV to 41.6 kV)

~~0.5320.677~~¢ per kWh for the first 100 hours use of maximum demand

~~0.5320.677~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

~~0.6000.274~~¢ per kWh for the first 100 hours use of maximum demand

~~0.6000.274~~¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute integrated demand created during the current billing month. This clause is applicable to each voltage level served.

MINIMUM CHARGES: 1) A monthly minimum charge of \$2.10 per kW of contract capacity shall be applied to that portion of the customer's load which is served under this rider. This minimum charge will be waived if the customer over the past 12 months (including the current bill), or from the start of the contract term if less than 12 months, has averaged \$2.10 per kW per month in revenues. This minimum charge is in addition to the minimum charge under the above rates, plus; 2) any applicable per meter per month surcharges.

POWER FACTOR CLAUSE (Retail Access Service Customers Only): A power factor of less than 70% is not permitted and necessary corrective equipment must be installed by the Customer to correct to a minimum level of 70%. Power factor and excess Reactive Demand charges will be calculated at each Customer location at the time of the Location's single highest 30-minute integrated kW reading of the Interval Demand Meter during the on-peak hours of the billing period, which are those hours from 7 a.m. until 11 p.m. consistent with the ITC Open Access Transmission Tariff. Excess Reactive Demand is any Reactive Demand resulting from operations below 80% power factor. A monthly charge of \$3.50/kVAR will be applied to excess Reactive Demand.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet the normal maximum requirements of the load qualifying for service under this rider. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for this rider shall not be included in the contract capacity established for the filed rate which is used in conjunction with this rider.

SPECIAL TERMS AND CONDITIONS: The customer is responsible for all new facilities and lines required for service under this rider. Said facilities and lines must meet all Company standards. The Company at its option may install and own said facilities under the provisions of Standard Contract Rider No. 2.

TERM: One year under written contract and month-to-month thereafter.

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(Continued from Sheet No. D-61.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.)

ELECTRIC PROCESS HEAT

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Capacity

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)

1.789~~0.706~~¢ per kWh for the first 100 hours use of maximum demand

0.676~~0.267~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

1.330~~0.525~~¢ per kWh for the first 100 hours use of maximum demand

0.484~~0.191~~¢ per kWh for the excess

For service at primary voltage level (24 kV to 41.6 kV)

1.297~~0.512~~¢ per kWh for the first 100 hours use of maximum demand

0.451~~0.178~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

1.100~~0.434~~¢ per kWh for the first 100 hours use of maximum demand

0.365~~0.144~~¢ per kWh for the excess

Non-Capacity

Energy Charge: 4.892~~5.251~~¢ per kWh for all kWh

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)

6.156~~5.288~~¢ per kWh for the first 100 hours use of maximum demand

6.156~~5.288~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

2.015~~1.832~~¢ per kWh for the first 100 hours use of maximum demand

2.015~~1.832~~¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)

0.532~~0.677~~¢ per kWh for the first 100 hours use of maximum demand

0.532~~0.677~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

0.600~~0.274~~¢ per kWh for the first 100 hours use of maximum demand

0.600~~0.274~~¢ per kWh for the excess

(Continued on Sheet No. D-63.00)

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Regulatory Affairs

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(Continued from Sheet No. D-62.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.)

ELECTRIC PROCESS HEAT

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Capacity (Only applicable to Retail Access Service Customers receiving Utility Capacity Service from DTE Electric)

Energy Charges:

For service at secondary voltage level (less than 4.8 kV)

1.789~~0.706~~¢ per kWh for the first 100 hours use of maximum demand

0.676~~0.267~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

1.330~~0.525~~¢ per kWh for the first 100 hours use of maximum demand

0.484~~0.191~~¢ per kWh for the excess

For service at subtransmission voltage level (24 kV to 41.6 kV)

1.297~~0.512~~¢ per kWh for the first 100 hours use of maximum demand

0.451~~0.178~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

1.100~~0.434~~¢ per kWh for the first 100 hours use of maximum demand

0.365~~0.144~~¢ per kWh for the excess

Capacity related surcharges and credits applicable to power supply, excluding PSCR, as approved by the Commission. See Section C8.5.

Delivery Charges:

Distribution Charges:

For service at secondary voltage level (less than 4.8 kV)

6.156~~5.288~~¢ per kWh for the first 100 hours use of maximum demand

6.156~~5.288~~¢ per kWh for the excess

For service at primary voltage level (4.8 kV to 13.2 kV)

2.015~~1.832~~¢ per kWh for the first 100 hours use of maximum demand

2.015~~1.832~~¢ per kWh for the excess

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(Continued from Sheet No. D-63.00)

STANDARD CONTRACT RIDER NO. 1.2 (Contd.)

ELECTRIC PROCESS HEAT

For service at subtransmission voltage level (24 kV to 41.6 kV)

~~0.5320.677~~¢ per kWh for the first 100 hours use of maximum demand

~~0.5320.677~~¢ per kWh for the excess

For service at transmission voltage level (120 kV and above)

~~0.6000.274~~¢ per kWh for the first 100 hours use of maximum demand

~~0.6000.274~~¢ per kWh for the excess

Substation Credit: Available to customers where service at sub-transmission voltage (24 kV to 41.6 kV) or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of 0.3¢/kWh will be applied to the energy use associated with the first 100 hours use of maximum demand.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MAXIMUM DEMANDS: The maximum demand shall be the highest 30-minute integrated demand created during the current billing month. This clause is applicable to each voltage level served.

MINIMUM CHARGES: 1) A monthly minimum charge of \$2.10 per kW of contract capacity shall be applied to that portion of the customer's load which is served under this rider. This minimum charge will be waived if the customer over the past 12 months (including the current bill), or from the start of the contract term if less than 12 months, has averaged \$2.10 per kW per month in revenues. This minimum charge is in addition to the minimum charge under the above rates, plus; 2) any applicable per meter per month surcharges.

POWER FACTOR CLAUSE (Retail Access Service Customers Only): A power factor of less than 70% is not permitted and necessary corrective equipment must be installed by the Customer to correct to a minimum level of 70%. Power factor and excess Reactive Demand charges will be calculated at each Customer location at the time of the Location's single highest 30-minute integrated kW reading of the Interval Demand Meter during the on-peak hours of the billing period, which are those hours from 7 a.m. until 11 p.m. consistent with the ITC Open Access Transmission Tariff. Excess Reactive Demand is any Reactive Demand resulting from operations below 80% power factor. A monthly charge of \$3.50/kVAR will be applied to excess Reactive Demand.

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet the normal maximum requirements of the load qualifying for service under this rider. Any single reading of the demand meter in any month that exceeds the contract capacity then in effect shall become the new contract capacity. The contract capacity for this rider shall not be included in the contract capacity established for the filed rate which is used in conjunction with this rider.

SPECIAL TERMS AND CONDITIONS: The customer is responsible for all new facilities and lines required for service under this rider. Said facilities and lines must meet all Company standards. The Company at its option may install and own said facilities under the provisions of Standard Contract Rider No. 2.

TERM: One year under written contract and month-to-month thereafter.

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**STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND
STATION POWER STANDBY SERVICE**

DEFINITIONS (contd):

MAINTENANCE PERIODS (contd):

- (e) If there is a substantial change in circumstances which make the agreed upon schedule impractical for either party, the other party upon request shall make reasonable efforts to adjust the schedule in a manner that is mutually agreeable.

WAIVERS AND LIMITS FOR GENERATION RESERVATION FEE AND DAILY DEMAND CHARGES:

For customers taking supplemental service on rate schedules D4, D11, D6.2 or D8, the following waivers apply:

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the generation reservation fee will be waived for that month.

Waivers and limits for energy-only rates:

For customers taking supplemental service on energy-only rates for the entire billing cycle, schedules D3, or D3.3, the following applies.

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the daily demand charges will be waived for that month provided that the supplemental rate continues as an energy-only rate. If not, then the total of daily demand charges for the month will be charged and the generation reservation fee for the month will be waived.

RATES:

Power Supply Charges:

Capacity

Monthly Generation Reservation Fee:

\$0.33 ~~0.13~~ times the standby contract capacity in kW, per month.

The daily on-peak backup demand charge is \$0.92 ~~0.36~~ per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is \$0.46 ~~0.18~~ per kW per day during maintenance periods as defined below.

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**STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND
STATION POWER STANDBY SERVICE**

RATES (contd):

Energy Charge:

For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer's supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Non-Capacity

Monthly Generation Reservation Fee:

\$0.30 ~~0.48~~ times the standby contract capacity in kW, per month.

The daily on-peak backup demand charge is \$0.83 ~~1.33~~ per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is \$0.42 ~~0.67~~ per kW per day during maintenance periods as defined below.

Energy Charge:

An energy charge for back-up and maintenance power will be charged based on standby contract capacity less the output toward internal load of the customer's generator, but not less than zero. For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be 5.016 ~~4.890~~¢ per kWh, plus appropriate power supply credits, including but not limited to an off-peak credit of 1.00¢ per kWh, and voltage level credits of 0.064 ~~0.062~~¢ per kWh for subtransmission and 0.143 ~~0.138~~¢ per kWh for transmission. For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer's supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Delivery Charges:

Service Charge:

\$70 per customer per month for customers served at primary voltage.

\$375 per customer per month for customers served above primary voltage.

\$70 per customer per month for customers served at secondary voltages.

Distribution Charge:

Distribution charges will be as follows:

\$6.66 ~~6.15~~ per kW at primary voltage applied to the standby contract capacity

\$1.82 ~~1.96~~ per kW at subtransmission voltage applied to the standby contract capacity

\$0.99 ~~0.86~~ per kW at transmission voltage applied to the standby contract capacity

(Continued on Sheet No. D-73.00)

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**STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND
STATION POWER STANDBY SERVICE**

RATES (contd):

Distribution Charge:

For service provided in conjunction with a secondary voltage base rate the Delivery Charge will be the greater of \$ ~~15.39~~ ~~13.22~~ per kW applied to standby contract capacity or ~~6.156~~ ~~5.288~~¢/kWh applied to all standby energy delivered.

Substation Credit: Available to customers served at subtransmission voltage level (24 to 41.6 kW) or higher who provide the on-site substation including all necessary transforming, controlling, and protective equipment. A credit of \$.30 per kW shall be applied to the distribution demand charge per kW of standby capacity. An additional credit of 0.040¢ per kWh of standby delivered will be given where the service is metered on the high voltage side of the transformer.

Surcharges and Credits Applicable to Delivery Service: As approved by the Commission. See Section C9.8.

ADJUSTMENT OF PRIOR RATCHETS: When a customer takes standby service under Rider No. 3, the setting or the increasing or decreasing of standby contract capacity will affect the existing ratchet levels on the supplemental rate as follows:

- (a) An amount in kW equal to the initial standby contract capacity (or to the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted maximum demand level for customers on supplemental rates D6.2 and D8 and D11.
- (b) An amount in kW equal to 65% of the initial standby contract capacity (or of the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted on-peak billing demand level for customers on supplemental rates D4, D6.2 and D8 and D11.

LATE PAYMENT CHARGE: See Section C4.8.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

POWER FACTOR CLAUSE: The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Customers are responsible for correcting power factors less than 70% at their own expense. The size, type and location of any power factor correction equipment must be approved by the Company. Such approval will not be unreasonably withheld. A penalty will be applied to the total amount of the monthly billing for supplemental and standby service for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The penalty will not be applied to the on-peak billing demand ratchet nor to the minimum contract demand of the supplemental rate, but will be applied to metered quantities.

(Continued on Sheet No. D-73.01)

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**STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND
STATION POWER STANDBY SERVICE**

STATION POWER STANDBY SERVICE

SERVICE UNDER THIS PROVISION BECOMES EFFECTIVE APRIL 1, 2014

STATION POWER STANDBY SERVICE: Available to customers with generation facilities that are located within the Company's retail service territory and that are interconnected to ITC Transmission. The power supply requirements necessary to maintain and operate the generating facility that are normally served by the facility's on-site generation but which instead are provided by the facility's taking power through its transmission interconnection must be provided under the station Power Standby Service provisions of this rider.

APPLICABLE TO: General Service Rate Schedule Designation D3

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CONTRACT CAPACITY: Customers shall initially contract for a specified capacity in kilowatts sufficient to meet expected maximum requirements. Any single reading of the demand meter or aggregation of demand meters recording inflow to the facility in any month that exceeds the contract capacity then in effect shall become the new contract capacity.

METERING REQUIREMENTS: All customers taking service under this rider must install the necessary equipment to permit metering. The Company will supply the metering equipment. Service to the customer under this Rider will be metered with demand-recording equipment. Any equipment installed by the customer necessary to accommodate the Company's metering equipment must be approved by the Company and must be compatible with the Company's Meter Data Acquisition System.

RATES:

Power Supply:

Non-Capacity

Station Power Energy Service will be priced on the basis of the real time MISO locational hourly marginal energy price for the Company-appropriate load node. In addition to the MISO locational hourly marginal energy price the following charges will also apply:

0.7690-767¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of 0.000¢/kWh plus,
Surcharges and Credits Applicable to Power Supply, excluding PSCR, as approved by the Commission. See Section C8.5

Service Charge:

Primary Service Charge:	\$70 per month
Subtransmission and Transmission Service Charge:	\$375 per month

(Continued on Sheet No. D-73.03)

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STANDARD CONTRACT RIDER NO. 7

GREENHOUSE LIGHTING SERVICE

APPLICABLE TO: General Service Rate
Large General Service Rate

Schedule Designation D3
Schedule Designation D4

Available on an optional basis to customers desiring high intensity discharge lighting service for greenhouses or other environmentally controlled growing facilities as a daylight supplement. All lighting on this rider shall be separately metered. The customer will furnish, install, own, and maintain all equipment comprising the lighting system. No other device may be connected to this circuit except for controls, lighting and associated equipment.

HOURS OF SERVICE: Dusk to dawn service for circuits controlled by photo-sensitive or clock timing devices.

CURRENT, PHASE AND VOLTAGE: Alternating current, 60 hertz, single phase, nominally at 120/240 volts, three-wire; or three-phase, four-wire, Y connected at 208Y/120 volts; or under certain conditions three-phase, four-wire, Y connected at 480Y/277 volts.

RATE PER MONTH:

Full Service Customers:

Power Supply Charge:

Capacity Energy Charge: ~~1.488~~~~0.577~~¢ per kWh for all kWh
Non-Capacity Energy Charge: ~~3.354~~~~4.054~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$1.95 per month
Distribution Charge: ~~6.156~~~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity Service for DTE:

Capacity Energy Charge: ~~1.488~~~~0.577~~¢ per kWh for all kWh

Delivery Charges:

Service Charge: \$1.95 per month
Distribution Charge: ~~6.156~~~~5.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

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STANDARD CONTRACT RIDER NO. 8

COMMERCIAL SPACE HEATING

APPLICABLE TO: General Service Rate
Large General Service Rate

Schedule Designation D3
Schedule Designation D4

Available on an optional basis to customers desiring service for commercial space conditioning furnished through separately metered circuits to which no other device except electric space heating, water heating, air conditioning, or humidity control equipment may be connected and provided that all of the space heating must be either total electric or an electric heat pump supplemented by a fossil fuel furnace installed on a permanent basis. The customer must provide special circuits, the design and method of installation of which are approved by the Company as adapted to this service.

Electric space heating under the terms of this rider will be considered to include heating by light systems, provided the primary means of space heating at the time of maximum requirements will be furnished by the lighting system, with the balance furnished by supplementary electric heating equipment. After June 15, 1970, under the authority of the Commission in Case U-3189, service to facilities which heat by lighting is not available for premises not previously qualified for service hereunder.

RATE PER MONTH:

Full Service Customers:

Power Supply Charge:

Capacity Energy Charge: ~~4.0131.539~~¢ per kWh for all kWh, except that during the billing months of November through May, usage in excess of 1,000 kWh per month shall be billed at ~~1.3300.510~~¢ per kWh.

Non-Capacity Energy Charge: ~~5.0996.173~~¢ per kWh

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: ~~6.1565.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity service from DTE:

Capacity Energy Charge: ~~4.0131.539~~¢ per kWh for all kWh, except that during the billing months of November through May, usage in excess of 1,000 kWh per month shall be billed at ~~1.3300.510~~¢ per kWh.

Delivery Charges:

Service Charge: \$11.25 per month

Distribution Charge: ~~6.1565.288~~¢ per kWh for all kWh

Surcharges and Credits: As approved by the Commission. See Section C9.8.

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STANDARD CONTRACT RIDER NO. 8 (Contd.)

COMMERCIAL SPACE HEATING

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus any applicable per meter per month surcharges.

CONTRACT TERM: This rate is made effective by a rider modifying the contract form prescribed for one of the applicable filed rates listed above. The contract term is co-extensive with the contract term of the applicable filed rate under which service is being taken.

INSULATION STANDARDS FOR ELECTRIC HEATING: See Section C4.9.

OPTIONAL PROVISION FOR CERTAIN COMMON AREA ACCOUNTS: Electric heating and common area usage of apartment or condominium accounts supplied through a single meter and billed under the terms of the Domestic Space Heating Rate D2 prior to September 28, 1978 may be billed under this provision without the necessity of separate metering if an initial block of kilowatthours is billed at the current General Service Rate D3. This initial block of kilowatthours will be calculated each November by averaging the usage during the previous billing months of June through October.

Full Service Customers:

Usage in excess of the initial block of kilowatthours per month shall be billed at a power supply capacity charge of ~~4.0131-539¢~~ and a non-capacity charge of ~~5.0996-173¢~~ per kilowatthour during the billing months of June through October, and a capacity charge of ~~1.3300-510¢~~ and a non-capacity charge of ~~5.0996-173¢~~ per kilowatthour during the billing months of November through May. A Distribution charge of ~~6.1565-288¢~~ per kWh for all kWh shall also be applied. The only service charge to be billed to a customer utilizing this provision will be the D3 service charge.

Retail Access Service Customers:

Power Supply Charge for Retail Access Service Customers taking Utility Capacity Service from DTE:

For Retail Access customers taking capacity service from DTE, usage in excess of the initial block of kilowatthours per month shall be billed at a power supply capacity charge of ~~4.0131-539¢~~ per kilowatthour during the billing months of June through October, and a power supply capacity charge of ~~1.3300-510¢~~ per kilowatthour during the billing months of November through May.

For all retail access customers, usage in excess of the initial block of kilowatthours per month shall be billed a distribution charge of ~~6.1565-288¢~~ per kWh for all kWh.

SUPPLEMENTAL SPACE HEATING PROVISION: This provision is available to customers taking service under the General Service Rate D3 or the Large General Service Rate D4 who purchase energy for a minimum of 10 kW of supplemental, permanently installed, electric space heating equipment. To qualify for this provision, a customer must certify in writing the amount of permanently installed space heating equipment, subject to inspection at the option of the Company, and have the said equipment on separately metered circuits to which no other device is connected. Section C4.9, Insulation Standards for Electric Heating, will not apply to this provision.

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STANDARD CONTRACT RIDER NO. 10 (Contd.)

INTERRUPTIBLE SUPPLY RIDER

CONTRACT CAPACITY: Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. Demand/Energy in excess of the contracted load level will be billed under the applicable Primary Supply Rate. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a specific reduction in connected load. Capacity disconnected from service under this rider shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods.

RATE PER MONTH:

Full Service Customers:

Power Supply Charges:

Non-Capacity:

The Energy charge will be the real time MISO locational hourly marginal energy price for the DTE Electric-appropriate load node. In addition to the MISO locational hourly marginal energy price the following charges will also apply:

~~0.769~~0.767¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of 0.000¢/kWh plus,
A voltage level service adder of 1.56% for transmission, 3.73% for subtransmission and 5.50% for primary.

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24kV) ~~\$6.66~~6.15 per kW of maximum demand

For service at subtransmission voltage (24 to 41.6 kV) ~~\$1.82~~1.96 per kW of maximum demand

For service at transmission voltage (120 kV and above) ~~\$0.99~~0.86 per kW of maximum demand.

Substation Credit: Available to customers where service at subtransmission voltage level or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Sections C8.5 and C9.8

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STANDARD CONTRACT RIDER NO. 10 (Contd.)

INTERRUPTIBLE SUPPLY RIDER

Retail Access Service Customers:

Delivery Charges:

Primary Service Charge: \$70 per month

Subtransmission and Transmission Service Charge: \$375 per month

Distribution Charges:

For primary service (less than 24kV) ~~\$6.66~~ ~~6.15~~ per kW of maximum demand

For service at subtransmission voltage (24 to 41.6 kV) ~~\$1.82~~ ~~1.96~~ per kW of maximum demand

For service at transmission voltage (120 kV and above) ~~\$0.99~~ ~~0.86~~ per kW of maximum demand.

Substation Credit: Available to customers where service at subtransmission voltage level or higher is required, who provide the on-site substation including all necessary transforming, controlling and protective equipment. A credit of \$.30 per kW of maximum demand shall be applied to the maximum demand charge. A credit of .040¢ per kWh shall be applied to the energy charge where the service is metered on the primary side of the transformer.

Surcharges and Credits: As approved by the Commission. See Section C9.8.

LATE PAYMENT CHARGE: See Section C4.8.

MINIMUM CHARGE: The Service Charge plus the Maximum Demand Charge, plus all applicable energy charges plus any applicable per meter per month surcharge.

MAXIMUM DEMAND: The maximum demand shall be the highest 30-minute demand created during the previous 12 billing months, including the current month but not less than 50% of the contract capacity. This clause is applicable to each voltage level served.

POWER FACTOR CLAUSE: Shall be the Power Factor Clause as defined in the Primary Supply Rate (D11).

SPECIAL TERMS AND CONDITIONS: Customer-owned equipment must be operated so the voltage fluctuations on the primary distribution system of the Company shall not exceed permissible limits.

The customer will own and maintain the necessary equipment to separate the interruptible load from the firm power load. This equipment must meet the Company standards. The customer must also provide space for the separate metering of the interruptible load.

The interruptible load shall not be served from firm power circuits at any time. Violations of this provision will result in a charge of \$50 per kilowatt per month applied to the interruptible load determined to have been served from firm power circuits.

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(Continued from Sheet D-114.00)

STANDARD CONTRACT RIDER NO. 18 (contd.)

DISTRIBUTED GENERATION PROGRAM

Rate Schedule	Outflow Credit \$ per kWh			
Residential				
D1/D1.6 Residential	First 17 kWh per Day: ~~\$0.09169~~ ~~0.08937~~	Excess: ~~\$0.10464~~ ~~0.09435~~		
D1.1 Int. Air	Summer: ~~\$0.07669~~ ~~0.07174~~	Winter: ~~\$0.05564~~ ~~0.06355~~		
D1.2 Time-of-Day	Summer On-Peak: ~~\$0.16429~~ ~~0.15639~~	Summer Off-Peak: ~~\$0.05531~~ ~~0.05265~~	Winter On-Peak: ~~\$0.13877~~ ~~0.13210~~	Winter Off-Peak: ~~\$0.05314~~ ~~0.05059~~
D1.7 Time-of-Day	Summer On-Peak: ~~\$0.14396~~ ~~0.08830~~	Summer Off-Peak: ~~\$0.04769~~ ~~0.04583~~	Winter On-Peak: ~~\$0.06220~~ ~~0.06299~~	Winter Off-Peak: ~~\$0.04888~~ ~~0.04951~~
D1.8 Dynamic Peak Pricing	Critical Peak: \$0.95000	On-Peak: ~~\$0.17931~~ ~~0.16814~~	Mid-Peak: ~~\$0.09256~~ ~~0.08779~~	Off-Peak: ~~\$0.04776~~ ~~0.04530~~
D1.9 Elec. Vehicle	On-Peak: ~~\$0.18087~~ ~~0.17105~~	Off-Peak: ~~\$0.04522~~ ~~0.04275~~		
D1.11 Stan. TOU	June-Sept On-Peak: ~~\$0.15073~~ ~~0.14261~~	June-Sept Off-Peak: ~~\$0.09081~~ ~~0.08595~~	Oct-May On-Peak: ~~\$0.10630~~ ~~0.09956~~	Oct-May Off-Peak: ~~\$0.09081~~ ~~0.08595~~
D1.13 Overnight Savers	On-Peak: June-Sept: ~~\$0.16771~~ ~~0.15744~~ Oct-Nov: ~~\$0.09565~~ ~~0.08990~~	Off-Peak: June-Sept: ~~\$0.11285~~ ~~0.10556~~ Oct-Nov: ~~\$0.08585~~ ~~0.08143~~	Super Off-Peak: June-Sept: ~~\$0.07127~~ ~~0.06798~~ Oct-Nov: ~~\$0.07127~~ ~~0.06798~~	
D2 Elec Space Heat	Summer First 17 kWh per Day: ~~\$0.08315~~ ~~0.07333~~	Summer Excess: ~~\$0.09525~~ ~~0.07788~~	Winter First 20 kWh per Day: ~~\$0.07158~~ ~~0.06898~~	Winter Excess: ~~\$0.06147~~ ~~0.06518~~
D5 Water Heat	All kWh: ~~\$0.05108~~ ~~0.04830~~			
Secondary				
D1.1 Int. Air	Summer: ~~\$0.07738~~ ~~0.07126~~	Winter: ~~\$0.06240~~ ~~0.06547~~		
D1.7 Time-of-Day	Summer On-Peak: ~~\$0.05177~~ ~~0.04952~~	Summer Off-Peak: ~~\$0.04729~~ ~~0.04523~~	Winter On-Peak: ~~\$0.04842~~ ~~0.04631~~	Winter Off-Peak: ~~\$0.04842~~ ~~0.04631~~
D1.8 Dynamic Peak Pricing	Critical Peak: \$0.95	On-Peak: ~~\$0.17434~~ ~~0.16545~~	Mid-Peak: ~~\$0.09367~~ ~~0.08982~~	Off-Peak: ~~\$0.04768~~ ~~0.04572~~
D1.9 Elec. Vehicle	On-Peak: ~~\$0.18087~~ ~~0.17105~~	Off-Peak: ~~\$0.04522~~ ~~0.04275~~		
D3 General Service	All kWh: ~~\$0.08475~~ ~~0.08106~~			
D3.2 Secondary Education	All kWh: ~~\$0.08190~~ ~~0.07876~~			
D3.3 Interruptible General Service	All kWh: ~~\$0.07081~~ ~~0.06773~~			
<u>D3.11 TOU General Service</u>	<u>June-Sept On-Peak:</u> <u>\$0.13334</u>	<u>June-Sept Off-Peak:</u> <u>\$0.07953</u>	<u>Oct-May On-Peak:</u> <u>\$0.08509</u>	<u>Oct-May Off-Peak:</u> <u>\$0.07953</u>
D4 Large General Service	Demand: ~~\$17.25~~ ~~16.59~~	First 200 kWh per kW: ~~\$0.04169~~ ~~0.04012~~	Excess: ~~\$0.03219~~ ~~0.03097~~	
D5 Water Heat	All kWh: ~~\$0.04991~~ ~~0.04773~~			
E1.1 Eng. St. Ltg.	All kWh: ~~\$0.05837~~ ~~0.05584~~			

(Continued on Sheet No. D-116.00)

Issued _____, 2025
M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after _____, 2025

Issued under authority of the
Michigan Public Service Commission
dated _____, 2025
in Case No. U-21534

(Continued from Sheet D-115.00)

STANDARD CONTRACT RIDER NO. 18 (contd.)

DISTRIBUTED GENERATION PROGRAM

Rate Schedule	Outflow Credit \$ per kWh			
Primary				
D11 Primary Supply	Demand:	On-Peak:	Off-Peak:	
Primary	~~\$17.54~~ ^{16.89} per kW	~~\$0.04388~~ ^{0.04257}	~~\$0.03388~~ ^{0.03257}	
Subtransmission	~~\$ 17.18~~ ^{16.58} per kW	~~\$ 0.04324~~ ^{0.04195}	~~\$0.03324~~ ^{0.03195}	
Transmission	~~\$16.80~~ ^{16.21} per kW	~~\$0.04245~~ ^{0.04119}	~~\$0.03245~~ ^{0.03119}	
D6.2 Primary Educational Institution	Demand:	On-Peak:	Off-Peak:	
Primary	~~\$15.35~~ ^{13.62} per kW	~~\$0.04837~~ ^{0.04322}	~~\$0.04537~~ ^{0.04022}	
Subtransmission	~~\$15.04~~ ^{13.37} per kW	~~\$0.04755~~ ^{0.04249}	~~\$0.04455~~ ^{0.03949}	
Transmission	~~\$14.71~~ ^{13.07} per kW	~~\$0.04655~~ ^{0.04160}	~~\$0.04355~~ ^{0.03860}	
D8 Interruptible Supply	Demand:	On-Peak	Off-Peak	
Primary	~~\$10.24~~ ^{10.12} per kW	~~\$0.04388~~ ^{0.04257}	~~\$0.03388~~ ^{0.03257}	
Subtransmission	~~\$10.03~~ ^{9.94} per kW	~~\$0.04324~~ ^{0.04195}	~~\$0.03324~~ ^{0.03195}	
Transmission	~~\$9.81~~ ^{9.72} per kW	~~\$0.04245~~ ^{0.04119}	~~\$0.03245~~ ^{0.03119}	
D10 All Electric School	Summer: ~~\$0.09842~~ ^{0.09537}	Winter: ~~\$0.07829~~ ^{0.07524}		
D13 XL	All kWh: ~~\$0.05109~~ ^{0.05248}			
D14 TOU Primary	June-Sept On-Peak:	June-Sept Off-Peak:	Oct-May On-Peak:	Oct-May Off-Peak:
Primary	~~\$0.10673~~	~~\$0.06351~~	~~\$0.07378~~	~~\$0.06351~~
Subtransmission	~~\$0.10551~~	~~\$0.06229~~	~~\$0.07256~~	~~\$0.06229~~
Transmission	~~\$0.10400~~	~~\$0.06078~~	~~\$0.07105~~	~~\$0.06078~~

(1) Retail Open Access Customers

The Outflow Credit will be determined by the Retail Service Supplier. For customers taking capacity service from the Company, the capacity outflow credit shall be the appropriate capacity rate(s) from the customer's rate schedule.

APPLICATION FOR SERVICE

In order to participate in the Distributed Generation Program, a customer shall submit completed Interconnection and Distributed Generation Program Applications, including the application fee of \$50 to the Company.

The Distributed Generation Program application fee is waived if the customer is transitioning from the Net Metering Program.

If a customer does not act or correspond on an application for over 6 months, when some action is required by the customer, the application may be voided by the Company.

(Continued on Sheet No. D-116.01)

Issued _____, 2025

M. A. Bruzzano
Senior Vice President
Regulatory Affairs

Detroit, Michigan

Effective for service rendered on
and after _____, 2025

Issued under authority of the
Michigan Public Service Commission
dated _____, 2025
in Case No. U-21534

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
EV Fast Charger General Service Rate
FOR DISCUSSION ONLY

Case No.: U-21534
Exhibit: A-16
Schedule: F9 Revised
Witness: A. Willis
Page: 1 of 1
Revised

Line	(a)	(b)	(c)	(d)
No.	Description	Billing Determinants Revised	Proposed Revised	
	Full Service Power Supply	<u>Quantity</u> <u>Units</u>	<u>Rate</u> <u>Revenue</u> (\$000)	
1	Capacity			
2	June - September			
3	On Peak (1pm - 5pm M-F)	753 MWh	\$0.04204	32
4	Off Peak	3,711 MWh	\$0.02508	93
5	October - May			
6	On Peak (1pm - 5pm M-F)	1,372 MWh	\$0.02683	37
7	Off Peak	6,924 MWh	\$0.02508	174
8				
9	Non-Capacity			
10	June - September			
11	On Peak (1pm - 5pm M-F)	753 MWh	\$0.10939	82
12	Off Peak	3,711 MWh	\$0.06524	242
13	October - May			
14	On Peak (1pm - 5pm M-F)	1,372 MWh	\$0.06981	96
15	Off Peak	6,924 MWh	\$0.06524	452
16				
17	PSCR	12,761 MWh	\$0	0
18	REPS	21 Meters	\$0	0
19	Total Full Service Power Supply	12,761 MWh	9.46¢	1,207
20				
21	Full Service Distribution	<u>Quantity</u> <u>Units</u>		
22				
23	Service Charge	21 Cust.	\$11.25	3
24				
25	Distribution Charge	12,761 MWh	\$0.11896	1,518
26	Distribution System	12,761 MWh	11.92¢	1,521
27	IRM	12,761 MWh	\$0.000595	8
28	Nuclear Decomm.	12,761 MWh	\$0.000882	11
29	Energy Optimization	21 Meters	\$5.50	1
30	LIEAF	21 Meters	\$0.88	0
31	Distribution Surcharges	12,761 MWh	0.16¢	20
32				
33	Total Full Service Distribution	12,761 MWh	12.08¢	1,541
34	Total Full Service	12,761 MWh	21.54¢	2,749

Michigan Public Service Commission
DTE Electric Company
2025 Forecast Energy Allocation Schedule

Case No.: U-21534
Exhibit: A-17
Schedule: G1.1
Witness: A. Willis
Page: 1 of 1

(a)		(b)	
Line No.	Rate Description	COS Class	Forecast
			Jan. 2025 - Dec. 2025 Energy (MWh)
1	<u>Residential</u>		
2	Residential	D1 & Other	16,168,548.1
3	Time-of-Day	D1.2	215,185.2
4	Space Heating	D2	309,045.4
5	Residential O.P.L.	E1/E2/D9	6,585.4
6	Total Residential		16,699,364.2
7			
8	<u>Secondary</u>		
9	General Service	D3 & Other	8,444,612.1
10	Large General Service	D4	1,900,717.2
11	Secondary Schools	D3.2	362,914.4
12	Commercial O.P.L.	E1/E2/D9	29,740.3
13	Traffic and Signal Lights	E1/E2/D9	65,304.1
14	Total Secondary		10,803,288.1
15			
16	<u>Primary</u>		
17	Primary Supply	D11 & Other	
18	Transmission Customer Owned Substation		1,088,595.7
19	Transmission DTE Owned Substation		3,359,951.3
20	Subtransmission Customer Owned Substation		368,323.3
21	Subtransmission DTE Owned Substation		1,003,183.2
22	Primary Distribution		6,219,810.6
23	Total Primary Supply		12,039,864.2
24			
25	Schools	D6.2	
26	Transmission Customer Owned Substation		0.0
27	Transmission DTE Owned Substation		0.0
28	Subtransmission Customer Owned Substation		1,557.6
29	Subtransmission DTE Owned Substation		337,466.3
30	Primary Distributuon		392,654.6
31	Total Schools		731,678.6
32			
33	Interruptible Primary Supply	D8	
34	Transmission Customer Owned Substation		127,054.2
35	Transmission DTE Owned Substation		0.0
36	Subtransmission Customer Owned Substation		3,462.6
37	Subtransmission DTE Owned Substation		61,818.3
38	Primary Distribution		339,386.8
39	Total Interruptible Primary		531,722.0
40			
41	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	
42	Transmission Customer Owned Substation		54,406.0
43	Transmission DTE Owned Substation		10,044.2
44	Subtransmission Customer Owned Substation		5,591.5
45	Subtransmission DTE Owned Substation		75,892.2
46	Primary Distribution		308,722.5
47	Secondary Distribution		41,525.4
48	Total Combined Alt. Metal Mltg. And Process Heat		496,181.7
49			
50	Interruptible Rider	R10	
51	Transmission Customer Owned Substation		0.0
52	Transmission DTE Owned Substation		0.0
53	Subtransmission Customer Owned Substation		0.0
54	Subtransmission DTE Owned Substation		0.0
55	Primary Distribution		0.0
56	Total Interruptible Rider		0.0
57			
58	Total Primary (lines 23 + 31 + 39 + 48 + 56)		13,799,446.4
59			
60	Street Lighting	E1/E2/D9	134,089.6
61			
62	TOTAL LOAD (lines 6 + 14 + 58 + 60)		41,436,188.3

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Power Plant Energy Production
Allocation Schedule 100 - Total Energy

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 1 of 13

		(a)	(b)	(c)
				Jan. 2025 - Dec. 2025
				Total Energy
				Schedule 100
Line				Allocation Factors
No.	Rate Description	COS Class		
1	<u>Residential</u>			
2	Residential	D1 & Other		0.39020
3	Time-of-Day	D1.2		0.00519
4	Space Heating	D2		0.00746
5	Residential O.P.L.	E1/E2/D9		0.00016
6	Total Residential			0.40301
7				
8	<u>Secondary</u>			
9	General Service	D3 & Other		0.20380
10	Large General Service	D4		0.04587
11	Schools - Secondary	D3.2		0.00876
12	Commercial O.P.L.	E1/E2/D9		0.00072
13	Traffic and Signal Lights	E1/E2/D9		0.00158
14	Total Secondary			0.26072
15				
16	<u>Primary</u>			
17	Primary Supply	D11 & Other		0.29056
18	Schools - Primary	D6.2		0.01766
19	Interruptible Primary Supply	D8		0.01283
20	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2		0.01197
21	Interruptible Rider	R10		-
22	Total Primary			0.33303
23				
24	Street Lighting	E1/E2/D9		0.00324
25				
26	TOTAL			1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Production System Output
Allocation Schedule 200A - 12CP

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 2 of 13

(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	12CP Demand
Rate Description			Schedule 200A
			Allocation Factors
1	Residential		
2	Residential	D1 & Other	0.44337
3	Time-of-Day	D1.2	0.00474
4	Space Heating	D2	0.00761
5	Residential O.P.L.	E1/E2/D9	0.00011
6	Total Residential		0.45584
7			
8	<u>Secondary</u>		
9	General Service	D3 & Other	0.20082
10	Large General Service	D4	0.04103
11	Schools - Secondary	D3.2	0.00836
12	Commercial O.P.L.	E1/E2/D9	0.00049
13	Traffic and Signal Lights	E1/E2/D9	0.00109
14	Total Secondary		0.25179
15			
16	<u>Primary</u>		
17	Primary Supply	D11 & Other	0.22645
18	Schools - Primary	D6.2	0.01632
19	Interruptible Primary Supply	D8	0.01053
20	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.01025
21	Interruptible Rider	R10	0.02659
22	Total Primary		0.29014
23			
24	Street Lighting	E1/E2/D9	0.00223
25			
26	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Production System Output
Allocation Schedule 200B - 4CP

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 3 of 13

(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			4CP Demand
			Schedule 200B
Line	Rate Description	COS Class	Allocation Factors
No.			
1	<u>Residential</u>		
2	Residential	D1 & Other	0.50799
3	Time-of-Day	D1.2	0.00420
4	Space Heating	D2	0.00523
5	Residential O.P.L.	E1/E2/D9	0.00000
6	Total Residential		0.51741
7			
8	<u>Secondary</u>		
9	General Service	D3 & Other	0.20523
10	Large General Service	D4	0.03976
11	Schools - Secondary	D3.2	0.00827
12	Commercial O.P.L.	E1/E2/D9	0.00000
13	Traffic and Signal Lights	E1/E2/D9	0.00088
14	Total Secondary		0.25415
15			
16	<u>Primary</u>		
17	Primary Supply	D11 & Other	0.20139
18	Schools - Primary	D6.2	0.01800
19	Interruptible Primary Supply	D8	0.00532
20	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.00373
21	Interruptible Rider	R10	0.00000
22	Total Primary		0.22844
23			
24	Street Lighting	E1/E2/D9	0.00000
25			
26	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Transmission Substation
Allocation Schedule 201 - 12CP

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 4 of 13

(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	12CP Demand
Rate Description			Schedule 201
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.46118
3	Residential O.P.L.	E1/E2/D9	0.00008
4	Total Residential		0.46126
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.28314
8	Commercial O.P.L.	E1/E2/D9	0.00034
9	Traffic and Signal Lights	E1/E2/D9	0.00111
10	Total Secondary		0.28460
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	0.21193
14	Subtransmission	Subtransmission	0.04055
15	Transmission	Transmission	-
16	Total Primary		0.25247
17			
18	Street Lighting	E1/E2/D9	0.00167
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Subtransmission Lines
Allocation Schedule 202A

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 5 of 13

(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 202A
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.52999
3	Residential O.P.L.	E1/E2/D9	0.00028
4	Total Residential		0.53027
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.25781
8	Commercial O.P.L.	E1/E2/D9	0.00101
9	Traffic and Signal Lights	E1/E2/D9	0.00068
10	Total Secondary		0.25950
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	0.18169
14	Subtransmission	Subtransmission	0.02497
15	Transmission	Transmission	-
16	Total Primary		0.20667
17			
18	Street Lighting	E1/E2/D9	0.00356
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Subtransmission Lines
Allocation Schedule 202B

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 6 of 13

(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 202B
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	-
3	Residential O.P.L.	E1/E2/D9	-
4	Total Residential		0.00000
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	-
8	Commercial O.P.L.	E1/E2/D9	-
9	Traffic and Signal Lights	E1/E2/D9	-
10	Total Secondary		0.00000
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	0.00000
14	Subtransmission	Subtransmission	1.00000
15	Transmission	Transmission	-
16	Total Primary		1.00000
17			
18	Street Lighting	E1/E2/D9	-
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Subtransmission Lines
Allocation Schedule 202C

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 7 of 13

(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 202C
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.52999
3	Residential O.P.L.	E1/E2/D9	0.00028
4	Total Residential		0.53027
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.25781
8	Commercial O.P.L.	E1/E2/D9	0.00101
9	Traffic and Signal Lights	E1/E2/D9	0.00068
10	Total Secondary		0.25950
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	N/A
14	Subtransmission	Subtransmission	0.02497
15	Transmission	Transmission	0.18169
16	Total Primary		0.20667
17			
18	Street Lighting	E1/E2/D9	0.00356
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Voltage Substation
Allocation Schedule 203A

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 8 of 13

	(a)	(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
Line			Schedule 203A
No.	Rate Description	COS Class	Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.54357
3	Residential O.P.L.	E1/E2/D9	0.00029
4	Total Residential		0.54385
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.26441
8	Commercial O.P.L.	E1/E2/D9	0.00104
9	Traffic and Signal Lights	E1/E2/D9	0.00070
10	Total Secondary		0.26615
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	0.18635
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	Total Primary		0.18635
17			
18	Street Lighting	E1/E2/D9	0.00365
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Voltage Substation
Allocation Schedule 203B

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
 Page: 9 of 13

(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
Line			Schedule 203B
No.	Rate Description	COS Class	Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	-
3	Residential O.P.L.	E1/E2/D9	-
4	Total Residential		0.00000
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	-
8	Commercial O.P.L.	E1/E2/D9	-
9	Traffic and Signal Lights	E1/E2/D9	-
10	Total Secondary		0.00000
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	-
14	Subtransmission	Subtransmission	0.33844
15	Transmission	Transmission	0.66156
16	Total Primary		1.00000
17			
18	Street Lighting	E1/E2/D9	-
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Voltage Substation
Allocation Schedule 203C

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 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
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(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
Line			Schedule 203C
No.	Rate Description	COS Class	Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.51315
3	Residential O.P.L.	E1/E2/D9	0.00027
4	Total Residential		0.51342
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.24961
8	Commercial O.P.L.	E1/E2/D9	0.00098
9	Traffic and Signal Lights	E1/E2/D9	0.00066
10	Total Secondary		0.25125
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	0.17592
14	Subtransmission	Subtransmission	0.01894
15	Transmission	Transmission	0.03702
16	Total Primary		0.23188
17			
18	Street Lighting	E1/E2/D9	0.00344
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Lines
Allocation Schedule 204

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
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(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
			Schedule 204
Line	Rate Description	COS Class	Allocation Factors
No.			
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.59870
3	Residential O.P.L.	E1/E2/D9	0.00032
4	Total Residential		0.59902
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.29123
8	Commercial O.P.L.	E1/E2/D9	0.00114
9	Traffic and Signal Lights	E1/E2/D9	0.00077
10	Total Secondary		0.29315
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	0.10431
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	Total Primary		0.10431
17			
18	Street Lighting	E1/E2/D9	0.00352
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Secondary Line Transformers
Allocation Schedule 205

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 205
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.66818
3	Residential O.P.L.	E1/E2/D9	0.00035
4	Total Residential		0.66853
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.32485
8	Commercial O.P.L.	E1/E2/D9	0.00127
9	Traffic and Signal Lights	E1/E2/D9	0.00086
10	Total Secondary		0.32698
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	-
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	Total Primary		0.00000
17			
18	Street Lighting	E1/E2/D9	0.00449
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Secondary Distribution Lines
Allocation Schedule 300

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.2
 Witness: A. Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 300
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.84697
3	Residential O.P.L.	E1/E2/D9	0.00012
4	Total Residential		0.84709
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.15164
8	Commercial O.P.L.	E1/E2/D9	0.00011
9	Traffic and Signal Lights	E1/E2/D9	0.00049
10	Total Secondary		0.15224
11			
12	<u>Primary</u>		
13	Primary Distribution	Primary	-
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	Total Primary		0.00000
17			
18	Street Lighting	E1/E2/D9	0.00068
19			
20	TOTAL		1.00000

**Michigan Public Service Commission
DTE Electric Company
2025 Forecast Energy Allocation Schedule**

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Schedule: G1.3
Witness: Willis
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(a)		(b)	
Line No.	Rate Description	COS Class	Forecast Jan. 2025 - Dec. 2025 Energy (MWh)
1	<u>Residential</u>		
2	Residential	D1 & Other	16,168,548.1
3	Time-of-Day	D1.2	215,185.2
4	Space Heating	D2	309,045.4
5	Residential O.P.L.	E1/E2/D9	6,585.4
6	Total Residential		16,699,364.2
7			
8	<u>Secondary</u>		
9	General Service	D3 & Other	8,428,437.5
10	Large General Service	D4	1,900,717.2
11	Secondary Schools	D3.2	362,914.4
12	Commercial O.P.L.	E1/E2/D9	29,740.3
13	Traffic and Signal Lights	E1/E2/D9	65,304.1
14	EV	EV	16,174.5
15	Total Secondary		10,803,288.1
16			
17	<u>Primary</u>		
18	Primary Supply	D11 & Other	
19	Transmission Customer Owned Substation		1,088,595.7
20	Transmission DTE Owned Substation		3,359,951.3
21	Subtransmission Customer Owned Substation		368,323.3
22	Subtransmission DTE Owned Substation		1,003,183.2
23	Primary Distribution		6,219,810.6
24	Total Primary Supply		12,039,864.2
25			
26	Schools	D6.2	
27	Transmission Customer Owned Substation		0.0
28	Transmission DTE Owned Substation		0.0
29	Subtransmission Customer Owned Substation		1,557.6
30	Subtransmission DTE Owned Substation		337,466.3
31	Primary Distributuon		392,654.6
32	Total Schools		731,678.6
33			
34	Interruptible Primary Supply	D8	
35	Transmission Customer Owned Substation		127,054.2
36	Transmission DTE Owned Substation		0.0
37	Subtransmission Customer Owned Substation		3,462.6
38	Subtransmission DTE Owned Substation		61,818.3
39	Primary Distribution		339,386.8
40	Total Interruptible Primary		531,722.0
41			
42	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	
43	Transmission Customer Owned Substation		54,406.0
44	Transmission DTE Owned Substation		10,044.2
45	Subtransmission Customer Owned Substation		5,591.5
46	Subtransmission DTE Owned Substation		75,892.2
47	Primary Distribution		308,722.5
48	Secondary Distribution		41,525.4
49	Total Combined Alt. Metal Mltg. And Process Heat		496,181.7
50			
51	Interruptible Rider	R10	
52	Transmission Customer Owned Substation		0.0
53	Transmission DTE Owned Substation		0.0
54	Subtransmission Customer Owned Substation		0.0
55	Subtransmission DTE Owned Substation		0.0
56	Primary Distribution		0.0
57	Total Interruptible Rider		0.0
58			
59	Total Primary (lines 23 + 31 + 39 + 48 + 56)		13,799,446.4
60			
61	Street Lighting	E1/E2/D9	134,089.6
62			
63	TOTAL LOAD (lines 6 + 14 + 58 + 60)		41,436,188.3

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Power Plant Energy Production
Allocation Schedule 100 - Total Energy

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 Witness: Willis
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Line No.	Rate Description	COS Class	(a)	(b)	(c)
			Jan. 2025 - Dec. 2025 Total Energy Schedule 100 Allocation Factors		
1	<u>Residential</u>				
2	Residential	D1 & Other			0.39020
3	Time-of-Day	D1.2			0.00519
4	Space Heating	D2			0.00746
5	Residential O.P.L.	E1/E2/D9			0.00016
6	Total Residential				0.40301
7					
8	<u>Secondary</u>				
9	General Service	D3 & Other			0.20341
10	Large General Service	D4			0.04587
11	Schools - Secondary	D3.2			0.00876
12	Commercial O.P.L.	E1/E2/D9			0.00072
13	Traffic and Signal Lights	E1/E2/D9			0.00158
14	EV	EV			0.00039
15	Total Secondary				0.26072
16					
17	<u>Primary</u>				
18	Primary Supply	D11 & Other			0.29056
19	Schools - Primary	D6.2			0.01766
20	Interruptible Primary Supply	D8			0.01283
21	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2			0.01197
22	Interruptible Rider	R10			-
23	Total Primary				0.33303
24					
25	Street Lighting	E1/E2/D9			0.00324
26					
27	TOTAL				1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Production System Output
Allocation Schedule 200A - 12CP

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 Witness: Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	12CP Demand
Rate Description			Schedule 200A
			Allocation Factors
1	Residential		
2	Residential	D1 & Other	0.44336
3	Time-of-Day	D1.2	0.00474
4	Space Heating	D2	0.00761
5	Residential O.P.L.	E1/E2/D9	0.00011
6	Total Residential		0.45583
7			
8	<u>Secondary</u>		
9	General Service	D3 & Other	0.20043
10	Large General Service	D4	0.04102
11	Schools - Secondary	D3.2	0.00836
12	Commercial O.P.L.	E1/E2/D9	0.00049
13	Traffic and Signal Lights	E1/E2/D9	0.00109
14	EV	EV	0.00041
15	Total Secondary		0.25180
16			
17	<u>Primary</u>		
18	Primary Supply	D11 & Other	0.22644
19	Schools - Primary	D6.2	0.01632
20	Interruptible Primary Supply	D8	0.01053
21	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.01026
22	Interruptible Rider	R10	0.02659
23	Total Primary		0.29014
24			
25	Street Lighting	E1/E2/D9	0.00223
26			
27	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Production System Output
Allocation Schedule 200B - 4CP

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 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	4CP Demand
Rate Description			Schedule 200B
			Allocation Factors
1	<u>Residential</u>		
2	Residential	D1 & Other	0.50802
3	Time-of-Day	D1.2	0.00420
4	Space Heating	D2	0.00522
5	Residential O.P.L.	E1/E2/D9	0.00000
6	Total Residential		0.51744
7			
8	<u>Secondary</u>		
9	General Service	D3 & Other	0.20485
10	Large General Service	D4	0.03977
11	Schools - Secondary	D3.2	0.00827
12	Commercial O.P.L.	E1/E2/D9	0.00000
13	Traffic and Signal Lights	E1/E2/D9	0.00088
14	EV	EV	0.00034
15	Total Secondary		0.25411
16			
17	<u>Primary</u>		
18	Primary Supply	D11 & Other	0.20140
19	Schools - Primary	D6.2	0.01800
20	Interruptible Primary Supply	D8	0.00532
21	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.00373
22	Interruptible Rider	R10	0.00000
23	Total Primary		0.22845
24			
25	Street Lighting	E1/E2/D9	0.00000
26			
27	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Transmission Substation
Allocation Schedule 201 - 12CP

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 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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		(a)	(b)	(c)
				Jan. 2025 - Dec. 2025
				12CP Demand
				Schedule 201
Line				Allocation Factors
No.	Rate Description	COS Class		
1	<u>Residential</u>			
2	Residential	Residential Secondary		0.46118
3	Residential O.P.L.	E1/E2/D9		0.00008
4	Total Residential			0.46125
5				
6	<u>Secondary</u>			
7	General Service	Commercial Secondary		0.28275
8	Commercial O.P.L.	E1/E2/D9		0.00034
9	Traffic and Signal Lights	E1/E2/D9		0.00111
10	EV	EV		0.00041
11	Total Secondary			0.28461
12				
13	<u>Primary</u>			
14	Primary Distribution	Primary		0.21193
15	Subtransmission	Subtransmission		0.04054
16	Transmission	Transmission		-
17	Total Primary			0.25247
18				
19	Street Lighting	E1/E2/D9		0.00167
20				
21	TOTAL			1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Subtransmission Lines
Allocation Schedule 202A

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
Line			Schedule 202A
No.	Rate Description	COS Class	Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.52980
3	Residential O.P.L.	E1/E2/D9	0.00028
4	Total Residential		0.53008
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.25749
8	Commercial O.P.L.	E1/E2/D9	0.00101
9	Traffic and Signal Lights	E1/E2/D9	0.00068
10	EV	EV	0.00058
11	Total Secondary		0.25976
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	0.18163
15	Subtransmission	Subtransmission	0.02497
16	Transmission	Transmission	-
17	Total Primary		0.20660
18			
19	Street Lighting	E1/E2/D9	0.00356
20			
21	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Subtransmission Lines
Allocation Schedule 202B

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 202B
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	-
3	Residential O.P.L.	E1/E2/D9	-
4	Total Residential		0.00000
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	-
8	Commercial O.P.L.	E1/E2/D9	-
9	Traffic and Signal Lights	E1/E2/D9	-
10	EV	EV	-
11	Total Secondary		0.00000
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	0.00000
15	Subtransmission	Subtransmission	1.00000
16	Transmission	Transmission	-
17	Total Primary		1.00000
18			
19	Street Lighting	E1/E2/D9	-
20			
21	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Input to Subtransmission Lines
Allocation Schedule 202C

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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		(a)	(b)	(c)
				Jan. 2025 - Dec. 2025
				Demand
				Schedule 202C
Line				Allocation Factors
No.	Rate Description	COS Class		
1	<u>Residential</u>			
2	Residential	Residential Secondary		0.52980
3	Residential O.P.L.	E1/E2/D9		0.00028
4	Total Residential			0.53008
5				
6	<u>Secondary</u>			
7	General Service	Commercial Secondary		0.25749
8	Commercial O.P.L.	E1/E2/D9		0.00101
9	Traffic and Signal Lights	E1/E2/D9		0.00068
10	EV	EV		0.00058
11	Total Secondary			0.25976
12				
13	<u>Primary</u>			
14	Primary Distribution	Primary		0.18163
15	Subtransmission	Subtransmission		0.02497
16	Transmission	Transmission		-
17	Total Primary			0.20660
18				
19	Street Lighting	E1/E2/D9		0.00356
20				
21	TOTAL			1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Voltage Substation
Allocation Schedule 203A

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
			Schedule 203A
Line	Rate Description	COS Class	Allocation Factors
No.			
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.54337
3	Residential O.P.L.	E1/E2/D9	0.00029
4	Total Residential		0.54366
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.26408
8	Commercial O.P.L.	E1/E2/D9	0.00104
9	Traffic and Signal Lights	E1/E2/D9	0.00070
10	EV	EV	0.00059
11	Total Secondary		0.26641
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	0.18628
15	Subtransmission	Subtransmission	-
16	Transmission	Transmission	-
17	Total Primary		0.18628
18			
19	Street Lighting	E1/E2/D9	0.00365
20			
21	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Voltage Substation
Allocation Schedule 203B

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
			Schedule 203B
Line	Rate Description	COS Class	Allocation Factors
No.			
1	<u>Residential</u>		
2	Residential	Residential Secondary	-
3	Residential O.P.L.	E1/E2/D9	-
4	Total Residential		0.00000
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	-
8	Commercial O.P.L.	E1/E2/D9	-
9	Traffic and Signal Lights	E1/E2/D9	-
10	EV	EV	-
11	Total Secondary		0.00000
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	-
15	Subtransmission	Subtransmission	0.33844
16	Transmission	Transmission	0.66156
17	Total Primary		1.00000
18			
19	Street Lighting	E1/E2/D9	-
20			
21	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Voltage Substation
Allocation Schedule 203C

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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		(a)	(b)	(c)
				Jan. 2025 - Dec. 2025
				Demand
				Schedule 203C
Line				Allocation Factors
No.	Rate Description	COS Class		
1	<u>Residential</u>			
2	Residential	Residential Secondary		0.51296
3	Residential O.P.L.	E1/E2/D9		0.00027
4	Total Residential			0.51323
5				
6	<u>Secondary</u>			
7	General Service	Commercial Secondary		0.24930
8	Commercial O.P.L.	E1/E2/D9		0.00098
9	Traffic and Signal Lights	E1/E2/D9		0.00066
10	EV	EV		0.00056
11	Total Secondary			0.25150
12				
13	<u>Primary</u>			
14	Primary Distribution	Primary		0.17586
15	Subtransmission	Subtransmission		0.01894
16	Transmission	Transmission		0.03702
17	Total Primary			0.23182
18				
19	Street Lighting	E1/E2/D9		0.00344
20				
21	TOTAL			1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Primary Lines
Allocation Schedule 204

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
			Jan. 2025 - Dec. 2025
			Demand
			Schedule 204
Line	Rate Description	COS Class	Allocation Factors
No.			
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.59844
3	Residential O.P.L.	E1/E2/D9	0.00032
4	Total Residential		0.59875
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.29085
8	Commercial O.P.L.	E1/E2/D9	0.00114
9	Traffic and Signal Lights	E1/E2/D9	0.00077
10	EV	EV	0.00065
11	Total Secondary		0.29341
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	0.10431
15	Subtransmission	Subtransmission	-
16	Transmission	Transmission	-
17	Total Primary		0.10431
18			
19	Street Lighting	E1/E2/D9	0.00352
20			
21	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Secondary Line Transformers
Allocation Schedule 205

Case No.: U-21534
 Exhibit: A-17
 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 205
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.66788
3	Residential O.P.L.	E1/E2/D9	0.00035
4	Total Residential		0.66823
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.32442
8	Commercial O.P.L.	E1/E2/D9	0.00127
9	Traffic and Signal Lights	E1/E2/D9	0.00086
10	EV	EV	0.00073
11	Total Secondary		0.32728
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	-
15	Subtransmission	Subtransmission	-
16	Transmission	Transmission	-
17	Total Primary		0.00000
18			
19	Street Lighting	E1/E2/D9	0.00448
20			
21	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
2025 Forecast Power Supply
Secondary Distribution Lines
Allocation Schedule 300

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 Schedule: G1.4
 Witness: Willis
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(a)		(b)	(c)
Line			Jan. 2025 - Dec. 2025
No.		COS Class	Demand
Rate Description			Schedule 300
			Allocation Factors
1	<u>Residential</u>		
2	Residential	Residential Secondary	0.84696
3	Residential O.P.L.	E1/E2/D9	0.00012
4	Total Residential		0.84708
5			
6	<u>Secondary</u>		
7	General Service	Commercial Secondary	0.15112
8	Commercial O.P.L.	E1/E2/D9	0.00011
9	Traffic and Signal Lights	E1/E2/D9	0.00049
10	EV	EV	0.00053
11	Total Secondary		0.15224
12			
13	<u>Primary</u>		
14	Primary Distribution	Primary	-
15	Subtransmission	Subtransmission	-
16	Transmission	Transmission	-
17	Total Primary		0.00000
18			
19	Street Lighting	E1/E2/D9	0.00068
20			
21	TOTAL		1.00000

**Michigan Public Service Commission
DTE Electric Company
Current and Historical Credit Ratings**

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Exhibit: A-18
Schedule: H1
Witness: T. J. Lepczyk
Page: 1 of 1

**Line
No.**

1	Standard & Poor's						
2		Current	Ratings at Year End				
3		Ratings	2022	2021	2020	2019	2018
4	DTE Electric						
5	Corporate Credit Rating	A-	A-	A-	A-	A-	BBB+
7	Senior Secured Debt	A	A	A	A	A	A
8	Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
9	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
10							
11	DTE Energy						
12	Corporate Credit Rating	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
13	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB	BBB
14	Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
15	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
16							
17							
18							
19	Moody's Investors Service						
20		Current	Ratings at Year End				
21		Ratings	2022	2021	2020	2019	2018
22	DTE Electric						
24	Senior Secured Debt	Aa3	Aa3	Aa3	Aa3	Aa3	Aa3
25	Commercial Paper	P-1	P-1	P-1	P-1	P-1	P-1
26	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
27							
28	DTE Energy						
29	Senior Unsecured Debt	Baa2	Baa2	Baa2	Baa2	Baa2	Baa1
30	Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-2
31	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
32							
33							
34							
35	Fitch Ratings						
36		Current	Ratings at Year End				
37		Ratings	2022	2021	2020	2019	2018
38	DTE Electric						
39	Senior Secured Debt	A+	A+	A+	A+	A+	A+
40	Commercial Paper	F2	F2	F2	F2	F2	F2
41	Outlook	Stable	Stable	Stable	Stable	Stable	Negative
42							
43	DTE Energy						
44	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB+	BBB+
45	Commercial Paper	F2	F2	F2	F2	F2	F2
46	Outlook	Stable	Stable	Stable	Stable	Negative	Negative

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

Case No.: U-21534
Exhibit: A-18
Schedule: H2
Witness: T. J. Lepczyk

Line No.	(a) Offer Date	(b) Issuer	(c) Credit Ratings			(f) Maturity	(g) Tenor	(h) Amount (\$MM)	(i) Coupon	(j) Spread
			Secured (?)	Moody's	S&P					
1	01/05/21	Southern California Edison Co	FMB	A3	A-	06/01/30	9 FXD	\$150	2.250%	85
2	01/05/21	Southern California Edison Co	FMB	A3	A-	02/01/51	30 FXD	\$750	2.950%	127
3	01/05/21	Ohio Power Co	Senior	A3	A-	01/15/31	10 FXD	\$450	1.625%	68
4	01/05/21	Southern Power Co	Senior	Baa1	BBB+	01/15/26	5 FXD	\$400	0.900%	57
5	02/01/21	National Rural Utilities Cooperative Fin	Senior	A2	A	02/08/24	3 FXD	\$500	0.350%	20
6	02/09/21	National Fuel Gas Co	Senior	Baa3	BBB-	03/01/31	10 FXD	\$500	2.950%	180
7	02/17/21	NextEra Energy Capital Holdings Inc.	Senior	Baa1	BBB+	02/22/23	2NC1 FRN	\$1,650	0.000%	27
8	02/22/21	Public Service Company of Colorado	FMB	A1	A	06/15/31	10 FXD	\$750	1.875%	58
9	02/22/21	Georgia Power Co.	Senior	Baa2	A-	03/15/51	30 FXD	\$750	3.250%	107
10	02/22/21	National Rural Utilities Cooperative Fin	Senior	A2	A	06/15/26	5 FXD	\$600	1.000%	45
11	02/23/21	Southern Co	Senior	Baa2	BBB+	02/26/24	3 FXD	\$600	0.600%	38
12	02/23/21	Southern Co	Senior	Baa2	BBB+	03/15/28	7 FXD	\$400	1.750%	80
13	02/23/21	Southwestern Public Service Co	Senior	A3	A	05/01/50	29 FXD	\$250	3.150%	95
14	02/24/21	Ameren Corp	Senior	Baa1	BBB	03/15/28	7 FXD	\$450	1.750%	75
15	02/26/21	Centerpoint Energy Respurces Corp	Senior	A3	BBB+	03/02/23	2NC1 FXD	\$700	0.700%	60
16	02/26/21	Centerpoint Energy Respurces Corp	Senior	A3	BBB+	03/02/23	2NC1 FRN	\$1,000	0.000%	50
17	03/01/21	PECO Energy Co	FMB	Aa3	A	03/15/51	30 FXD	\$375	3.050%	82
18	03/02/21	Commonwealth Edison Inc.	FMB	A1	A	03/15/51	30 FXD	\$700	3.125%	90
19	03/02/21	Entergy	Senior	Baa2	BBB	06/15/28	7 FXD	\$650	1.900%	87
20	03/02/21	Entergy	Senior	Baa2	BBB	06/15/31	10 FXD	\$650	2.400%	107
21	03/02/21	Public Service Electric & Gas Co.	Senior	Aa3	A	03/15/26	5 FXD	\$450	0.950%	32
22	03/02/21	Public Service Electric & Gas Co.	Senior	Aa3	A	03/01/51	30 FXD	\$450	3.000%	77
23	03/03/21	Atlantic City Electric	FMB	A2	A	03/15/31	10 FXD	\$350	2.300%	83
24	03/08/21	Eversource Energy	Senior	Baa1	BBB+	03/15/31	10 FXD	\$350	2.550%	100
25	03/08/21	One Gas	Senior	A3	BBB+	03/11/23	2NC1 FXD	\$1,000	0.850%	70
26	03/08/21	One Gas	Senior	A3	BBB+	03/11/23	2NC1 FRN	\$800	0.000%	61
27	03/08/21	One Gas	Senior	A3	BBB+	03/11/24	3NC1 FXD	\$700	1.100%	80
28	03/08/21	Piedmont Natural Gas Co Inc	Senior	A3	BBB+	03/15/31	10 FXD	\$350	2.500%	95
29	03/08/21	Southwestern Electric Power Co	Senior	Baa2	A-	03/15/26	5 FXD	\$500	1.650%	80
30	03/08/21	CenterPoint Energy Houston Electric LLSenior Secured	A2	A	A	04/01/31	10 FXD	\$400	2.350%	80
31	03/08/21	CenterPoint Energy Houston Electric LLSenior Secured	A2	A	A	04/01/51	30 FXD	\$700	3.350%	105
32	03/08/21	Pacific Gas and Electric Co	Senior Secured	Baa3	BBB-	03/10/23	2NC1 FXD	\$1,500	1.367%	120
33	03/08/21	Pacific Gas and Electric Co	Senior Secured	Baa3	BBB-	06/01/31	10 FXD	\$450	3.250%	167
34	03/08/21	Pacific Gas and Electric Co	Senior Secured	Baa3	BBB-	06/01/41	20 FXD	\$450	4.200%	200
35	03/09/21	Appalachian Power Co	Senior	Baa1	A-	04/01/31	10 FXD	\$400	2.700%	120
36	03/09/21	Entergy Mississippi LLC	Senior Secured	A2	A	06/01/51	30 FXD	\$200	3.500%	115
37	03/15/21	NextEra Energy	Senior	Baa1	BBB+	03/01/23	2 FXD	\$2,000	0.650%	50
38	03/15/21	NextEra Energy	Senior	Baa1	BBB+	03/01/23	2 FRN	\$500	0.000%	54
39	03/15/21	Tampa Electric Co.	Senior	A3	BBB+	03/15/31	10 FXD	\$400	2.400%	83
40	03/15/21	Tampa Electric Co.	Senior	A3	BBB+	03/15/51	30 FXD	\$400	3.450%	108
41	03/16/21	WEC Energy Group Inc	Senior	Baa1	BBB+	03/15/24	3 FXD	\$600	0.800%	48
42	03/17/21	FirstEnergy Transmission LLC	Senior	Baa2	BB+	09/15/28	7 FXD	\$500	2.866%	0.02870
43	03/22/21	DTE Electric Company	FMB	Aa3	A	04/01/28	7 FXD	\$575	1.900%	58
44	03/22/21	DTE Electric Company	FMB	Aa3	A	04/01/51	30 FXD	\$425	3.250%	90
45	03/23/21	Northern States Power Co/MN	FMB	Aa3	A	04/01/31	10 FXD	\$425	2.250%	65
46	03/23/21	Northern States Power Co/MN	FMB	Aa3	A	04/01/52	31 FXD	\$425	3.200%	85
47	03/24/21	Entergy Arkansas LLC	FMB	A2	A	06/15/52	31 FXD	\$400	3.350%	105
48	03/24/21	Southern California Edison Co	FMB	A3	A-	04/03/23	2 FXD	\$350	0.700%	60
49	03/24/21	Southern California Edison Co	FMB	A3	A-	04/03/23	2 FRN	\$400	0.000%	64
50	03/24/21	Southern California Edison Co	FMB	A3	A-	04/01/24	3NC2 FXD	\$700	1.100%	80
51	03/24/21	Dominion Energy	Senior	Baa2	BBB	04/15/26	5 FXD	\$600	1.450%	65
52	03/24/21	Dominion Energy	Senior	Baa2	BBB	04/15/41	20 FXD	\$500	3.300%	110
53	03/24/21	Southern California Edison Co	Senior	A3	A-	04/01/24	3NC2 FRN	\$400	0.000%	83
54	03/29/21	Duke Energy Carolinas LLC	FMB	Aa3	A	04/15/31	10 FXD	\$550	2.550%	85
55	03/29/21	Duke Energy Carolinas LLC	FMB	Aa3	A	04/15/51	30 FXD	\$450	3.450%	105

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

Case No.: U-21534
Exhibit: A-18
Schedule: H2
Witness: T. J. Lepczyk

Line No.	(a) Offer Date	(b) Issuer	(c) Credit Ratings			(f) Maturity	(g) Tenor	(h) Amount (\$MM)	(i) Coupon	(j) Spread
			Secured (?)	Moody's	S&P					
56	04/07/21	Monongahela Power Co	FMB	A3	BBB	05/15/27	6 FXD	\$200	3.550%	120
57	04/07/21	Northern Natural Gas Co	Senior	A2	A	10/16/51	31 FXD	\$550	3.400%	110
58	04/15/21	Essential Utilities Inc	Senior	Baa2	A-	05/01/31	10 FXD	\$400	2.400%	88
59	04/27/21	Indiana Michigan Power Co	Senior	A3	A-	05/01/51	30 FXD	\$450	3.250%	100
60	04/29/21	Toledo Edison Co/The	FMB	A2	BBB	05/01/28	7 FXD	\$150	2.650%	137.5
61	05/04/21	AEP Texas Inc	Senior	Baa2	A-	05/15/51	30 FXD	\$450	3.450%	120
62	05/05/21	Florida Power & Light Co	Senior	A1	A	05/10/23	2NC1 FRN	\$1,000	0.000%	25
63	05/06/21	Tucson Electric Power Co	Senior	A3	A-	05/01/51	30 FXD	\$325	3.250%	105
64	05/10/21	American Water Capital Corp	Senior	Baa1	A	06/01/31	10 FXD	\$550	2.300%	73
65	05/10/21	American Water Capital Corp	Senior	Baa1	A	06/01/51	30 FXD	\$550	3.250%	93
66	05/11/21	CenterPoint Energy Inc (CNP)	Senior	Baa2	BBB	05/13/24	3NC1 FRN	\$700	0.000%	65
67	05/11/21	CenterPoint Energy Inc (CNP)	Senior	Baa2	BBB	06/01/26	5 FXD	\$500	1.450%	70
68	05/11/21	CenterPoint Energy Inc (CNP)	Senior	Baa2	BBB	06/01/31	10 FXD	\$500	2.650%	105
69	05/13/21	Spire Missouri Inc	Senior	A1	A	06/01/51	30 FXD	\$305	3.300%	90
70	05/20/21	Mid-Atlantic Interstate Transmission LLC	Senior	A3	BB+	05/15/28	7 FXD	\$150	4.100%	125
71	05/24/21	NSTAR Electric Co	Senior	A1	A	06/01/51	30 FXD	\$300	3.100%	83
72	05/24/21	OGE Energy Corp	Senior	Baa1	BBB+	05/26/23	2NC1 FXD	\$500	0.703%	55
73	05/24/21	Oklahoma Gas and Electric Co	Senior	A3	A-	05/26/23	2NC1 FXD	\$500	0.553%	40
74	05/25/21	Emera US Finance LP	Senior	Baa3	BBB-	06/15/24	3 FXD	\$300	0.833%	53
75	05/25/21	Emera US Finance LP	Senior	Baa3	BBB-	06/15/31	10 FXD	\$450	2.639%	108
76	06/01/21	Pacific Gas and Electric Co	FMB	Baa3	BBB-	06/15/28	7 FXD	\$800	3.000%	180
77	06/01/21	Public Service Co of New Hampshire	FMB	A1	A+	06/15/31	10 FXD	\$350	2.200%	62
78	06/02/21	NextEra Energy Capital Holdings Inc	Senior	Baa1	BBB+	06/15/28	7 FXD	\$1,500	1.900%	65
79	06/03/21	Puget Energy Inc	Secured	Baa3	BBB-	06/15/28	7 FXD	\$500	2.379%	108
80	06/03/21	Consolidated Edison Co of New York Inc	Senior	Baa1	A-	06/15/31	10 FXD	\$750	2.400%	80
81	06/03/21	Consolidated Edison Co of New York Inc	Senior	Baa1	A-	06/15/61	40 FXD	\$750	3.600%	130
82	06/07/21	Alabama Power Co	Senior	A1	A	07/15/51	30 FXD	\$600	3.125%	87.5
83	06/07/21	Baltimore Gas and Electric Co	Senior	A3	A	06/15/31	10 FXD	\$600	2.250%	70
84	06/07/21	Duke Energy	Senior	Baa2	BBB	06/10/23	2 FRN	\$500	0.000%	25
85	06/07/21	Duke Energy	Senior	Baa2	BBB	06/15/31	10 FXD	\$1,000	2.550%	100
86	06/07/21	Duke Energy	Senior	Baa2	BBB	06/15/41	20 FXD	\$750	3.300%	115
87	06/07/21	Duke Energy	Senior	Baa2	BBB	06/15/51	30 FXD	\$750	3.500%	125
88	06/08/21	Jersey Central Power & Light Co	Senior	A3	BB+	03/01/32	11 FXD	\$500	2.750%	125
89	06/08/21	Wisconsin Electric Power Co	Senior	A2	A-	06/15/28	7 FXD	\$300	1.700%	50
90	06/09/21	Southern California Edison Co	FMB	A3	A-	06/01/31	10 FXD	\$450	2.500%	105
91	06/09/21	Southern California Edison Co	FMB	A3	A-	06/13/22	1 FRN	\$475	0.000%	35
92	06/09/21	Southern California Edison Co	FMB	A3	A-	06/01/51	30 FXD	\$450	3.650%	148
93	06/09/21	Union Electric Co	FMB	A2	A	03/15/32	11 FXD	\$525	2.150%	67
94	06/21/21	Connecticut Light and Power Co/The	FMB	A1	A+	07/01/31	10 FXD	\$425	2.050%	60
95	06/21/21	PPL Electric Utilities Corp	FMB	A1	A	06/24/24	3NC1 FRN	\$650	0.000%	33
96	06/22/21	Ameren Illinois Co	FMB	A1	A	06/15/23	2 FXD	\$100	0.375%	15
97	06/22/21	Ameren Illinois Co	FMB	A1	A	06/15/51	30 FXD	\$350	2.900%	80
98	06/22/21	Duquesne Light Holdings Inc	Senior	Baa3	BBB-	01/07/32	11 FXD	\$400	2.775%	130
99	06/24/21	Mississippi Power Co	Senior	Baa1	A-	06/28/24	3 FRN	\$200	0.000%	30
100	06/24/21	Mississippi Power Co	Senior	Baa1	A-	07/30/51	30 FXD	\$325	3.100%	105
101	07/07/21	PacifiCorp	FMB	A1	A+	06/15/52	31 FXD	\$750	2.900%	98
102	07/07/21	Enel Finance International NV	Senior	Baa1	BBB+	07/12/26	5 FXD	\$1,250	1.375%	70
103	07/07/21	Enel Finance International NV	Senior	Baa1	BBB+	07/12/28	7 FXD	\$1,000	1.875%	85
104	07/07/21	Enel Finance International NV	Senior	Baa1	BBB+	07/12/31	10 FXD	\$1,000	2.250%	100
105	07/07/21	Enel Finance International NV	Senior	Baa1	BBB+	07/12/41	20 FXD	\$750	2.875%	110
106	07/20/21	MidAmerican Energy Co	Secured	A2	A+	08/01/52	31 FXD	\$500	2.700%	85
107	08/02/21	Consumers Energy	FMB	A1	A	08/15/52	31 FXD	\$300	2.650%	78
108	08/02/21	AEP Transmission Co LLC	Senior	A2	A-	08/15/51	30 FXD	\$450	2.750%	90
109	08/05/21	Commonwealth Edison Co.	FMB	A1	A	09/01/51	30 FXD	\$450	2.750%	87
110	08/05/21	Southern California Edison Co.	FMB	A3	A-	08/01/23	2 FXD	\$400	0.700%	50

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

Case No.: U-21534
Exhibit: A-18
Schedule: H2
Witness: T. J. Lepczyk

Line No.	(a) Offer Date	(b) Issuer	(c) Credit Ratings			(f) Maturity	(g) Tenor	(h) Amount (\$MM)	(i) Coupon	(j) Spread
			Secured (?)	Moody's	S&P					
111	08/05/21	Southern California Edison Co.	FMB	A3	BBB+	08/01/24	3 FXD	\$450	0.975%	60
112	08/09/21	Duke Energy Progress LLC	FMB	Aa3	A	08/15/31	10 FXD	\$650	2.000%	70
113	08/09/21	Duke Energy Progress LLC	FMB	Aa3	A	08/15/51	30 FXD	\$450	2.900%	93
114	08/09/21	San Diego Gas & Electric Co	FMB	A1	A	08/15/51	30 FXD	\$750	2.950%	100
115	08/10/21	Dominion Energy	Senior	Baa2	BBB	08/15/31	10 FXD	\$1,000	2.250%	92
116	08/10/21	Eversource Energy	Senior	Baa1	BBB+	08/15/23	2 FRN	\$350	0.000%	25
117	08/10/21	Eversource Energy	Senior	Baa1	BBB+	08/15/26	5 FXD	\$300	1.400%	60
118	08/10/21	NSTAR Electric Co	Senior	A1	A	08/15/31	10 FXD	\$300	1.950%	67
119	08/11/21	Arizona Public Service Co	Senior	A2	A-	12/15/31	10 FXD	\$450	2.200%	87.5
120	08/11/21	Entergy Texas Inc	Senior	Baa1	A	09/01/26	5 FXD	\$130	1.500%	75
121	08/11/21	Public Service Co of Oklahoma	Senior	Baa1	A-	08/15/31	10 FXD	\$400	2.200%	90
122	08/11/21	Public Service Co of Oklahoma	Senior	Baa1	A-	08/15/51	30 FXD	\$400	3.150%	115
123	08/17/21	Public Service Electric and Gas Co	Senior	Aa3	A	08/15/31	10 FXD	\$425	1.900%	68
124	08/18/21	Southwest Gas Corp	Senior	Baa1	A-	08/15/51	30 FXD	\$300	3.180%	128
125	08/23/21	Black Hills Corp	Senior	Baa2	BBB+	08/23/24	3NC1 FXD	\$600	1.037%	60
126	09/07/21	PECO Energy Co	FMB	Aa3	A	09/15/51	30 FXD	\$375	2.850%	88
127	09/07/21	Southern Co Gas Capital Corp	Senior	Baa1	A-	09/30/51	30 FXD	\$450	3.150%	123
128	09/08/21	Cleco Power	Senior	A3	BBB+	06/15/23	2 FRN	\$325	0.000%	50
129	09/08/21	Puget Sound Energy	Senior	A2	A-	09/15/51	30 FXD	\$450	2.893%	95
130	09/09/21	Ohio Power	Senior	A3	A-	10/01/51	30 FXD	\$600	2.900%	103
131	09/13/21	Wisconsin Power and Light	Senior	A3	A	09/16/31	10 FXD	\$300	1.950%	63
132	09/14/21	The Southern Co	Jr Sub	Baa3/BBB-		NA	60NC6 FXD/FRN	\$1,250	1.875%	0.01875
133	09/21/21	Atmos Energy Corp	Senior	A1/A-		02/15/52	30 FXD	\$600	2.850%	103
134	09/21/21	New York State Electric & Gas Corp	Senior	Baa1/A-		10/01/31	10 FXD	\$350	2.150%	85
135	09/23/21	Duke Energy Corp	Jr Sub	Baa3/BBB-		01/15/82	60NC5 FXD/FXD	\$500	3.250%	0.0325
136	09/28/21	Entergy Louisiana LLC	Secured	A2/A		10/01/24	3NC1 FXD	\$1,000	0.950%	45
137	10/18/21	National Rural Utilities Cooperative Fin	Senior	A2/A-		10/18/24	3 FXD	\$400	1.000%	30
138	10/18/21	National Rural Utilities Cooperative Fin	Senior	A2/A-		10/18/24	3 FRN	\$350	--	33
139	10/27/21	NextEra Energy Capital	Senior	Baa1/BBB+		11/03/23	2NC1 FRN	\$1,300	--	40
140	10/29/21	Xcel Energy Inc	Senior	Baa1/BBB+		03/15/27	5 FXD	\$500	1.750%	62
141	10/29/21	Xcel Energy Inc	Senior	Baa1/BBB+		11/15/31	10 FXD	\$300	2.350%	82
142	11/01/21	Southwestern Electric Power	Senior	Baa2/BBB+		11/01/51	30 FXD	\$650	3.250%	130
143	11/04/21	Edison International	Pref	Baa2/BB+		12/31/99	1024 FXD/FXD	\$750	3.901%	0.05
144	11/04/21	Public Service Enterprise Group Inc	Senior	Baa2/BBB		11/08/23	2NC1 FXD	\$750	0.841%	43
145	11/04/21	Public Service Enterprise Group Inc	Senior	Baa2/BBB		11/15/31	10 FXD	\$750	2.450%	95
146	11/05/21	Southern Co / The	Senior	Baa2/BBB		NA	2NC1 FRN	\$600	--	37
147	11/08/21	Northwest Natural Gas	FMB	A2/AA-		12/01/51	30 FXD	\$130	3.078%	120
148	11/10/21	American Electric Power	Jr Sub	Baa3/BB+/BBB		02/15/62	40NC5 FXD/FXD	\$750	3.875%	0.03875
149	11/10/21	Entergy Mississippi Llc	FMB	A2/A/A		12/01/33	12 FXD	\$200	2.550%	105
150	11/10/21	Oncor Electric Delivery	Senior	A2/A+		NA	10 FXD	\$300	--	58
151	11/10/21	Oncor Electric Delivery	FMB	A2/A+		11/15/51	30 FXD	\$500	2.700%	88
152	11/10/21	Pacific Gas & Electric	FMB	Baa3/BBB-		11/15/22	1 FRN	\$300	--	115
153	11/10/21	Pacific Gas and Electric Co	FMB	Baa3/BBB-		06/01/31	10 FXD	\$550	3.250%	158
154	11/10/21	Pacific Gas and Electric Co	FMB	Baa3/BBB-		11/15/23	2NC1 FXD	\$900	1.700%	125
155	11/10/21	Wisconsin Public Service	Senior	A2/A-		12/01/51	30 FXD	\$450	2.850%	95
156	11/15/21	Alabama Power Co	Senior	A1/A-		03/15/52	30 FXD	\$700	3.000%	100
157	11/15/21	Ameren Corp	Senior	Baa1/BBB		03/15/27	5 FXD	\$500	1.950%	70
158	11/15/21	DTE Energy Co	Jr Sub	Baa3/BBB-		12/01/81	60NC5 FXD	\$280	4.375%	0.04375
159	11/15/21	Sempra Energy	Jr Sub	Baa3/BBB-		04/01/52	30NC5 FXD/FXD	\$1,000	4.125%	0.04125
160	11/15/21	Virginia Electric and Power	Senior	A2/BBB+		11/15/31	10 FXD	\$500	2.300%	70
161	11/15/21	Virginia Electric and Power	Senior	A2/BBB+		11/15/51	30 FXD	\$500	2.950%	95
162	11/16/21	Florida Light & Power Co	FMB	Aa2/A+		12/04/51	30 FXD	\$1,200	2.875%	85
163	11/16/21	Interstate Power and Light Co	Senior	Baa1/A-		11/30/51	30 FXD	\$300	3.100%	110
164	11/18/21	Dominion Energy South Carolina Inc	FMB	A3/A		12/01/31	10 FXD	\$300	2.300%	72
165	11/29/21	American Transmission Systems Inc	Senior	A3/BBB		01/15/32	10 FXD	\$600	2.650%	115

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

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			Secured (?)	Moody's	S&P					
166	11/29/21	Consolidated Edison Co of New York	Senior	Baa1/A-		06/15/31	10 FXD	\$150	2.400%	87
167	11/29/21	Consolidated Edison Co of New York	Senior	Baa1/A-		12/01/51	30 FXD	\$600	3.200%	132
168	11/29/21	Duke Energy Florida LLC	FMB	A1/A		12/15/31	10 FXD	\$650	2.400%	90
169	11/29/21	Duke Energy Florida LLC	FMB	A1/A		12/15/51	30 FXD	\$500	3.000%	115
170	12/01/21	Dominion Energy Inc	Jr Sub	Ba1/BBB-		12/31/99	PerpNC5 FXD/FXD	\$750	4.350%	0.0435
171	12/01/21	Southern California Edison Co	FMB	A3/A-		12/02/22	1 FRN	\$550	--	47
172	12/01/21	Spire Missouri Inc	FMB	A1/A		12/02/24	3NC1 FRN	\$300	--	50
173	12/06/21	WEC Energy	Senior	Baa1/BBB+		12/15/28	7 FXD	\$500	2.200%	85
174	12/08/21	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		01/15/27	5 FXD	\$1,000	1.875%	62
175	12/08/21	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		01/15/32	10 FXD	\$1,000	2.440%	92
176	12/08/21	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		01/15/52	30 FXD	\$500	3.000%	112
177	12/09/21	NextEra Energy Capital Holdings Inc	Jr Sub	Baa2/BBB		03/15/82	60NC5 FXD/FXD	\$600	3.800%	0.038
178	01/04/22	American Electric Power Co	Jr Sub	Baa3/BBB+		03/15/24	2 FXD	\$805	2.031%	85
179	01/05/22	Niagara Mohawk Power Corp	Senior	Baa1/BBB+		01/10/32	10 FXD	\$400	2.759%	105
180	01/05/22	Virginia Electric and Power Co	Senior	A2/BBB+		11/15/51	30 FXD	\$400	2.950%	98
181	01/05/22	Virginia Electric and Power Co	Senior	A2/BBB+		03/30/32	10 FXD	\$600	2.400%	70
182	01/06/22	Semptra Infrastructure Partners LP	Senior	Baa3/BBB-		NA	10 FXD	\$400	--	165
183	01/10/22	Southern California Edison Co	FMB	A3/A-		02/01/32	10 FXD	\$500	2.750%	98
184	01/10/22	Southern California Edison Co	FMB	A3/A-		02/01/52	30 FXD	\$700	3.450%	135
185	01/11/22	Atmos Energy Corp	Senior	A1/A-		09/15/29	10 FXD	\$200	2.625%	68
186	01/12/22	Algonquin Power & Utilities Corp	Jr Sub	NR/BB+		01/18/82	60NC5 FXD/FXD	\$750	4.750%	0.0475
187	01/12/22	Florida Power & Light Co	FMB	Aa2/A+		02/03/32	10 FXD	\$1,500	2.450%	73
188	01/12/22	Florida Power & Light Co	Senior	Aa2/A+		01/12/24	2NC0 FRN	\$1,000	--	38
189	01/12/22	KeySpan Gas East Corp	Senior	Baa1/BBB+		01/18/52	30 FXD	\$400	3.586%	150
190	01/31/22	National Rural Utilities Cooperative Fin	Secured	A1/A-		04/15/32	10 FXD	\$500	2.750%	100
191	01/31/22	National Rural Utilities Cooperative Fin	Senior	A2/A-		08/07/23	2 FRN	\$400	--	40
192	01/31/22	National Rural Utilities Cooperative Fin	Senior	A2/A-		02/07/25	3 FXD	\$600	1.875%	50
193	02/02/22	Fells Point Funding Trust / Constellation	Senior	Baa2/BBB-		NA	5 FXD	\$1,000	--	145
194	02/15/22	Tuscon Electric Power Co	Senior	A3/A-		05/15/32	10 FXD	\$325	3.250%	125
195	02/16/22	DTE Electric Co	Secured	Aa3/A		03/01/32	10 FXD	\$500	3.000%	100
196	02/16/22	DTE Electric Co	Secured	Aa3/A		03/01/52	30 FXD	\$400	3.650%	130
197	02/16/22	Pacific Gas & Electric Co	FMB	Baaa3/BBB-		02/16/24	2NC1 FXD	\$1,000	3.250%	175
198	02/16/22	Pacific Gas & Electric Co	FMB	Baaa3/BBB-		03/01/29	7 FXD	\$400	4.200%	220
199	02/16/22	Pacific Gas & Electric Co	FMB	Baaa3/BBB-		03/01/32	10 FXD	\$450	4.400%	240
200	02/16/22	Pacific Gas & Electric Co	FMB	Baaa3/BBB-		03/01/52	30 FXD	\$550	5.250%	290
201	02/22/22	Eversource Energy	Senior	Baa1/BBB+		03/01/32	10 FXD	\$650	3.375%	145
202	02/22/22	Eversource Energy	Senior	Baa1/BBB+		03/01/27	5 FXD	\$650	2.900%	105
203	02/23/22	Alliant Energy Finance LLC	Senior	Baa2/BBB+		03/01/32	10 FXD	\$350	3.600%	165
204	02/23/22	CenterPoint Energy Houston Electric LL	FMB	A2/A		03/01/32	10 FXD	\$300	3.000%	107
205	02/23/22	CenterPoint Energy Houston Electric LL	FMB	A2/A		03/01/52	30 FXD	\$500	3.600%	137
206	03/01/22	Duke Energy Carolinas	FMB	Aa3/A		03/15/32	10 FXD	\$500	2.850%	115
207	03/01/22	Duke Energy Carolinas	FMB	Aa3/A		03/15/52	30 FXD	\$650	3.550%	145
208	03/02/22	Alabama Power Co	Senior	A1/A-		03/15/32	10 FXD	\$700	3.050%	120
209	03/02/22	Entergy Arkansas	FMB	A2/A-		04/01/49	30 FXD	\$200	4.200%	160
210	03/02/22	Exelon Corp	Senior	Baa2/BBB		03/15/27	5 FXD	\$650	2.750%	100
211	03/02/22	Exelon Corp	Senior	Baa2/BBB		03/15/32	10 FXD	\$650	3.350%	145
212	03/02/22	Exelon Corp	Senior	Baa2/BBB		03/15/52	30 FXD	\$700	4.100%	180
213	03/07/22	San Diego Gas & Electric Co	FMB	A1/A		03/15/32	10 FXD	\$500	3.000%	128
214	03/07/22	San Diego Gas & Electric Co	FMB	A1/A		03/15/52	30 FXD	\$500	3.700%	155
215	03/08/22	Avista Corp	FMB	A3/A-		04/01/52	30 FXD	\$400	4.000%	175
216	03/08/22	Commonwealth Edison Co	FMB	A1/A		03/15/52	30 FXD	\$450	3.850%	160
217	03/08/22	Commonwealth Edison Co	FMB	A1/A		03/15/32	10 FXD	\$300	3.150%	130
218	03/08/22	Southern California Gas Co	Senior	A2/A		04/15/27	5 FXD	\$700	2.950%	125
219	03/09/22	Public Service Electric and Gas Co	Secured	A1/A		03/15/32	10 FXD	\$500	3.100%	120
220	03/10/22	Eergy Missouri West Inc	FMB	A3/A		03/15/32	10 FXD	\$250	3.750%	175

Michigan Public Service Commission
DTE Electric Company
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			Secured (?)	Moody's	S&P					
221	03/11/22	Boston Gas Company	Senior	Baa1/BBB+		03/16/32	10 FXD	\$400	3.757%	175
222	03/14/22	Duke Energy Progress LLC	FMB	Aa3/A		04/01/32	10 FXD	\$500	3.400%	130
223	03/14/22	Duke Energy Progress LLC	FMB	Aa3/A		04/01/52	30 FXD	\$400	4.000%	155
224	03/14/22	Puget Energy Inc	Secured	Baa3/BBB-		03/15/32	10 FXD	\$450	4.224%	210
225	03/17/22	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		03/21/24	2NC1 FXD	\$1,100	2.940%	100
226	03/17/22	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		03/21/24	2NC1 FRN	\$400	--	102
227	03/17/22	Southwest Gas Corp	Senior	Baa1/BBB		03/15/32	10 FXD	\$600	4.050%	190
228	03/21/22	Sempra Energy	Senior	Baa2/BBB		04/01/25	3 FXD	\$750	3.300%	102
229	03/21/22	Sempra Energy	Senior	Baa2/BBB		04/01/29	7 FXD	\$500	3.700%	140
230	03/21/22	Union Electric Co	FMB	A2/A		04/01/52	30 FXD	\$525	3.900%	135
231	04/04/22	Oglethorpe Power Corp	FMB	Baa1/BBB+		04/01/47	25 FXD	\$500	4.500%	205
232	04/19/22	Berkshire Hathaway Energy Co	Senior	A3/A-		05/01/53	31 FXD	\$1,000	4.600%	162.5
233	04/27/22	National Rural Utilities Co	Senior	A2/A-		06/15/25	3 FXD	\$300	3.450%	75
234	05/02/22	American Water Capital Corp	Senior	Baa1/A		06/01/32	10 FXD	\$800	4.450%	150
235	05/02/22	Georgia Power Co	Senior	Baa1/BBB+		05/15/32	10 FXD	\$700	4.700%	175
236	05/02/22	Georgia Power Co	Senior	Baa1/BBB+		05/15/52	30 FXD	\$800	5.125%	210
237	05/02/22	Northern States Power Co/MN	FMB	Aa3/A		06/01/52	30 FXD	\$500	4.500%	148
238	05/03/22	Xcel Energy Inc	Senior	Baa1/BBB+		06/01/32	10 FXD	\$700	4.600%	167
239	05/05/22	Southern Company/The	Jr Sub	Baa3/BBB		NA	2 FXD	\$863	--	155
240	05/05/22	Southern Company/The	Jr Sub	Baa3/BBB		NA	5 FXD	\$863	--	200
241	05/10/22	Piedmont Natural Gas Co Inc	Senior	A3/BBB+		05/15/52	30 FXD	\$400	5.050%	197
242	05/10/22	Public Service Co of Colorado	FMB	A1/A		06/01/32	10 FXD	\$300	4.100%	120
243	05/10/22	Public Service Co of Colorado	FMB	A1/A		06/01/52	30 FXD	\$400	4.500%	145
244	05/10/22	Vistra Operations Co LLC	Secured	Baa3/BBB-		05/13/24	2NC1 FXD	\$400	4.875%	225
245	05/10/22	Vistra Operations Co LLC	Secured	Baa3/BBB-		05/13/25	3 FXD	\$1,100	5.125%	237.5
246	05/12/22	NSTAR Electric Co	Senior	A1/A		06/01/52	30 FXD	\$450	4.550%	157
247	05/16/22	AEP Texas Inc	Senior	Baa2/A-		05/15/32	10 FXD	\$500	4.700%	185
248	05/16/22	AEP Texas Inc	Senior	Baa2/A-		05/15/52	30 FXD	\$500	5.250%	215
249	05/16/22	Virginia Electric and Power Co	Senior	A2/BBB+		05/15/27	5 FXD	\$600	3.750%	98
250	05/16/22	Virginia Electric and Power Co	Senior	A2/BBB+		05/15/52	30 FXD	\$600	4.625%	160
251	05/17/22	Oncor Electric Delivery Co LLC	FMB	A2/A+		06/01/32	10 FXD	\$400	4.150%	122
252	05/17/22	Oncor Electric Delivery Co LLC	FMB	A2/A+		06/01/52	30 FXD	\$400	4.600%	147
253	05/17/22	PECO Energy Co	FMB	Aa3/A		05/15/52	30 FXD	\$350	4.600%	147
254	05/18/22	Essential Utilities Inc	Senior	Baa2/A-		05/01/52	30 FXD	\$500	5.300%	225
255	05/18/22	Southern California Edison Co	FMB	A3/A-		06/01/25	3 FXD	\$300	4.200%	140
256	05/18/22	Southern California Edison Co	FMB	A3/A-		06/01/27	5 FXD	\$600	4.700%	185
257	05/18/22	Southern California Edison Co	FMB	A3/A-		06/01/52	30 FXD	\$350	5.450%	240
258	05/23/22	Southwestern Public Service Co	FMB	A3/A		06/01/52	30 FXD	\$200	5.150%	210
259	06/01/22	Baltimore Gas and Electric Co	Senior	A3/A		06/01/52	30 FXD	\$500	4.550%	145
260	06/06/22	Pacific Gas and Electric	FMB	Baa3/BBB-		06/08/25	3 FXD	\$450	4.950%	205
261	06/06/22	Pacific Gas and Electric	FMB	Baa3/BBB-		06/15/27	5 FXD	\$450	5.450%	245
262	06/06/22	Pacific Gas and Electric	FMB	Baa3/BBB-		06/15/32	10 FXD	\$600	5.900%	205
263	06/07/22	AEP Transmission Co	Senior	A2/A-		06/15/52	30 FXD	\$550	4.500%	140
264	06/07/22	Centerpoint Energy Resources	Senior	A3/BBB+		07/01/32	10 FXD	\$500	4.400%	145
265	06/07/22	NiSource Inc	Senior	Baa2/BBB+		06/15/52	30 FXD	\$350	5.000%	190
266	06/08/22	Enel Finance International	Senior	Baa1/BBB+		06/15/25	3 FXD	\$750	4.250%	145
267	06/08/22	Enel Finance International	Senior	Baa1/BBB+		06/15/27	5 FXD	\$750	4.625%	165
268	06/08/22	Enel Finance International	Senior	Baa1/BBB+		06/15/32	10 FXD	\$1,000	5.000%	215
269	06/08/22	Enel Finance International	Senior	Baa1/BBB+		06/15/52	30 FXD	\$1,000	5.500%	240
270	06/21/22	Nextera Energy Capital	Senior	Baa1/BBB+		06/20/24	2 FXD	\$750	4.200%	100
271	06/21/22	Nextera Energy Capital	Senior	Baa1/BBB+		06/20/25	3 FXD	\$1,000	4.450%	110
272	06/21/22	Nextera Energy Capital	Senior	Baa1/BBB+		07/15/27	5 FXD	\$1,250	4.625%	125
273	06/21/22	Nextera Energy Capital	Senior	Baa1/BBB+		07/15/32	10 FXD	\$1,000	5.000%	170
274	06/22/22	Eversource Energy	Senior	Baa1/BBB+		07/01/27	5 FXD	\$600	4.600%	140
275	06/22/22	Eversource Energy	Senior	Baa1/BBB+		06/27/24	3 FXD	\$900	4.200%	115

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			Secured (?)	Moody's	S&P					
276	07/07/22	Tampa Electric Co	Senior	A3/BBB+		07/12/24	2 FXD	\$300	3.875%	85
277	07/07/22	Tampa Electric Co	Senior	A3/BBB+		07/15/52	30 FXD	\$300	5.000%	180
278	07/28/22	Appalachian Power	Senior	Baa1/A-		04/01/32	10 FXD	\$500	4.500%	185
279	08/01/22	Consumers Energy Co	FMB	A1/A		08/15/32	10 FXD	\$350	3.600%	100
280	08/01/22	Consumers Energy Co	FMB	A1/A		09/01/52	30 FXD	\$450	4.200%	125
281	08/01/22	Edison International	Senior	Baa3/BBB-		08/15/25	3 FXD	\$400	4.700%	190
282	08/02/22	Brooklyn Union Gas Co/The	Senior	Baa2/BBB+		08/05/27	5 FXD	\$400	4.632%	177
283	08/02/22	Brooklyn Union Gas Co/The	Senior	Baa2/BBB+		08/05/32	10 FXD	\$400	4.866%	212
284	08/02/22	NextEra Energy Capital Holdings	Senior	Baa1/BBB+		09/01/24	2 FXD	\$1,500	4.255%	105
285	08/03/22	DTE Energy Co	Senior	Baa2/BBB		11/01/24	2 FXD	\$1,300	4.220%	112.5
286	08/04/22	ONE Gas Inc.	Senior	A3/BBB+		09/01/32	10 FXD	\$300	4.250%	165
287	08/08/22	Duke Energy Corp	Senior	Baa2/BBB		03/15/28	5 FXD	\$900	4.300%	142
288	08/08/22	Duke Energy Corp	Senior	Baa2/BBB		08/15/32	10 FXD	\$1,150	4.500%	177
289	08/08/22	Duke Energy Corp	Senior	Baa2/BBB		08/15/52	30 FXD	\$1,150	5.000%	202
290	08/08/22	Wisconsin Power and Light Co	Senior	A3/A		09/01/32	10 FXD	\$600	3.950%	132
291	08/09/22	Alabama Power Co	Senior	A1/A-		09/01/27	5 FXD	\$550	3.750%	80
292	08/09/22	Alabama Power Co	Senior	A1/A-		09/01/32	10 FXD	\$450	3.940%	115
293	08/09/22	Dominion Energy Inc	Senior	Baa2/BBB		08/15/32	10 FXD	\$400	4.350%	165
294	08/09/22	Dominion Energy Inc	Senior	Baa2/BBB		08/15/52	30 FXD	\$600	4.850%	190
295	08/10/22	National Rural Utilities Cooperative Fin	Senior	A1/A-		12/15/32	10 FXD	\$400	4.150%	140
296	08/15/22	Ameren Illinois Co	FMB	A1/A		09/01/32	10 FXD	\$500	3.850%	108
297	08/16/22	PECO Energy Co	FMB	Aa3/A		08/15/52	30 FXD	\$425	4.375%	127
298	08/18/22	Entergy Louisiana LLC	FMB	A2/A		09/15/52	30 FXD	\$500	4.750%	162.5
299	08/22/22	Entergy Texas, Inc.	FMB	A3/A-		09/15/52	30 FXD	\$325	5.000%	178
300	09/06/22	Oncor Electric Delivery Co LLC	Senior	A2/A+		09/15/32	10 FXD	\$700	4.550%	123
301	09/06/22	Oncor Electric Delivery Co LLC	Senior	A2/A+		09/15/52	30 FXD	\$500	4.950%	148
302	09/06/22	Southern Co Gas Capital Corp	Senior	Baa1/BBB+		09/15/32	10 FXD	\$500	5.150%	185
303	09/08/22	ITC Holdings Corp	Senior	Baa2/BBB+		09/22/27	5 FXD	\$600	4.950%	158
304	09/12/22	CenterPoint Energy Houston Electric LL	Secured	A2/A		10/01/32	10 FXD	\$500	4.450%	115
305	09/12/22	CenterPoint Energy Houston Electric LL	Secured	A2/A		10/01/52	30 FXD	\$300	4.850%	137.5
306	09/12/22	NSTAR Electric Co	Senior	A1/A		09/15/52	30 FXD	\$400	4.950%	147
307	09/12/22	Niagara Mohawk Power Corp	Senior	Baa1/BBB+		09/16/52	30 FXD	\$500	5.783%	225
308	09/14/22	Wisconsin Electric Power Co	Senior	A2/A-		09/30/32	10 FXD	\$500	4.750%	135
309	09/22/22	Ohio Edison Co	Senior	A3/BBB		01/15/33	10 FXD	\$300	5.500%	185
310	09/22/22	WEC Energy Group Inc	Senior	Baa1/BBB+		09/27/25	3 FXD	\$500	5.000%	90
311	09/22/22	WEC Energy Group Inc	Senior	Baa1/BBB+		10/01/27	5 FXD	\$400	5.150%	128
312	09/27/22	Atmos Energy Group	Senior	A1/A-		10/15/32	10 FXD	\$300	5.450%	152
313	09/27/22	Atmos Energy Group	Senior	A1/A-		10/15/52	30 FXD	\$500	5.750%	195
314	10/03/22	The Southern Co	Senior	Baa2/BBB		10/15/32	10 FXD	\$500	5.700%	205
315	10/03/22	The Southern Co	Senior	Baa2/BBB		10/06/25	3 FXD	\$500	5.150%	110
316	10/03/22	EDP Finance	Senior	Baa3/BBB		10/11/27	5 FXD	\$500	6.300%	245
317	10/06/22	Enel Finance International NV	Senior	Baa1/BBB+		10/14/52	30 FXD	\$1,000	7.750%	440
318	10/06/22	Enel Finance International NV	Senior	Baa1/BBB+		10/14/32	10 FXD	\$1,250	7.500%	400
319	10/06/22	Enel Finance International NV	Senior	Baa1/BBB+		10/14/25	3 FXD	\$750	6.800%	275
320	10/06/22	Enel Finance America LLC	Senior	Baa1/BBB+		10/14/27	5 FXD	\$1,000	7.100%	325
321	10/17/22	Nevada Power Co	Senior	A2/A+		05/01/53	30 FXD	\$400	5.900%	190
322	10/20/22	National Rural Utilities Cooperative Fin	Senior	A2/A-		10/30/25	3 FXD	\$500	5.450%	85
323	10/20/22	National Rural Utilities Cooperative Fin	CTB	A2/A-		01/15/33	10 FXD	\$350	5.800%	158
324	10/31/22	American Electric Power Company Inc	Senior	Baa2/BBB+		11/01/32	10 FXD	\$500	5.950%	195
325	10/31/22	American Electric Power Company Inc	Senior	Baa2/BBB+		11/01/27	5 FXD	\$500	5.750%	155
326	11/03/22	Southern California Edison Co	Senior	A3/A-		11/01/32	10 FXD	\$750	5.950%	190
327	11/03/22	Southern California Edison Co	Senior	A3/A-		11/01/27	5 FXD	\$750	5.850%	150
328	11/04/22	Public Service Enterprise	Senior	Baa2/BBB		11/15/27	5 FXD	\$700	5.850%	155
329	11/04/22	Arizona Public Service Co	Senior	A3/BBB+		12/15/32	10 FXD	\$400	6.350%	220
330	11/07/22	Wisconsin Public Service Corp	Senior	A2/A-		11/10/25	3 FXD	\$300	5.350%	72

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

Case No.: U-21534
Exhibit: A-18
Schedule: H2
Witness: T. J. Lepczyk

Line No.	(a) Offer Date	(b) Issuer	(c) Secured (?)	(d) Credit Ratings Moody's	(e) S&P	(f) Maturity	(g) Tenor	(h) Amount (\$MM)	(i) Coupon	(j) Spread
331	11/07/22	Southern California Gas Co	FMB	Aa3/A+		11/15/52	30 FXD	\$600	6.350%	205
332	11/07/22	Edison	Senior	Baa3/BBB-		11/15/29	7 FXD	\$550	6.950%	280
333	11/07/22	Duke Energy Florida LLC	FMB	A1/A		11/15/52	30 FXD	\$500	5.950%	167
334	11/08/22	Indianapolis Power & Light Co	FMB	A2/A-		12/01/32	10 FXD	\$350	5.650%	155
335	11/08/22	Ameren Illinois CO	FMB	A1/A		12/01/52	30 FXD	\$350	5.900%	163
336	11/08/22	Indianapolis Power & Light Co	FMB	A2/A-		12/01/32	10 FXD	\$350	--	155
337	11/09/22	Consolidated Edison Co of New York	Senior	Baa1/A-		11/15/52	30 FXD	\$700	6.150%	185
338	11/16/22	Dominion Energy	Senior	Baa2/BBB		11/15/32	10 FXD	\$850	5.375%	175
339	11/21/22	New England Power Co	Senior	A3/BBB+		11/25/52	30 FXD	\$300	5.936%	200
340	11/28/22	Evergy Missouri West Inc	FMB	A3/A		12/15/27	5 FXD	\$300	5.150%	130
341	11/29/22	PacifiCorp	FMB	A1/A+		12/01/53	31 FXD	\$1,100	5.350%	153
342	11/29/22	Southwest Gas Corp	Senior	Baa1/BBB		12/01/27	5 FXD	\$300	5.800%	190
343	11/30/22	Public Service Electric and Gas Co	FMB	A1/A		12/15/32	10 FXD	\$400	4.900%	112.5
344	12/05/22	Duke Energy	Senior	Baa2/BBB		12/08/25	3 FXD	\$500	5.000%	88
345	12/05/22	Duke Energy	Senior	Baa2/BBB		12/08/27	5 FXD	\$500	5.000%	123
346	12/07/22	National Rural Utilities Cooperative Fin	Senior	A2/A-		03/15/28	5 FXD	\$400	4.800%	120
347	01/03/23	The Connecticut Light and Power Co	FMB	A1/A+		01/15/53	30 FXD	\$500	5.250%	135
348	01/03/23	Public Service Co of Oklahoma	Senior	Baa1/A-		01/15/33	10 FXD	\$475	5.250%	150
349	01/03/23	Oklahoma Gas and Electric Co	Senior	A3/A-		01/15/33	10 FXD	\$450	5.400%	165
350	01/03/23	Entergy Arkansas LLC	FMB	A2/A		01/15/33	10 FXD	\$425	5.150%	140
351	01/03/23	Duke Energy Carolinas LLC	FMB	Aa3/A		01/15/53	30 FXD	\$900	5.350%	145
352	01/03/23	Duke Energy Carolinas LLC	FMB	Aa3/A		01/15/33	10 FXD	\$900	4.950%	120
353	01/03/23	Consumers Energy Co	FMB	A1/A		03/01/28	5 FXD	\$425	4.650%	75
354	01/03/23	Commonwealth Edison Co	FMB	A1/A		02/01/53	30 FXD	\$575	5.300%	140
355	01/03/23	Commonwealth Edison Co	FMB	A1/A		02/01/33	10 FXD	\$400	4.900%	115
356	01/04/23	Public Service Co of New Hampshire	FMB	A1/A+		01/15/53	30 FXD	\$300	5.150%	133
357	01/04/23	Pacific Gas and Electric Co	FMB	Baa3/BBB-		01/15/33	10 FXD	\$750	6.150%	250
358	01/04/23	Pacific Gas and Electric Co	FMB	Baa3/BBB-		01/15/53	30 FXD	\$750	6.750%	295
359	01/09/23	WEC Energy Group Inc	Senior	Baa1/BBB+		01/15/28	5 FXD	\$450	4.750%	112.5
360	01/09/23	WEC Energy Group Inc	Senior	Baa1/BBB+		01/09/26	3 FXD	\$650	4.750%	85
361	02/02/23	National Rural Utilities Cooperative Fin	Senior	A2/A-		03/13/26	3 FXD	\$600	4.450%	70
362	02/02/23	National Rural Utilities Cooperative Fin	Senior	A2/A-		03/15/28	5 FXD	\$200	4.800%	95
363	02/02/23	National Rural Utilities Cooperative Fin	Senior	A1/A-		01/15/33	10 FXD	\$300	5.800%	123
364	02/06/23	Spire Missouri Inc	FMB	A1/A		02/15/33	10 FXD	\$400	4.800%	120
365	02/06/23	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		02/28/53	30 FXD	\$1,150	5.250%	155
366	02/06/23	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		02/28/33	10 FXD	\$1,000	5.050%	140
367	02/06/23	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		02/28/30	7 FXD	\$600	5.000%	125
368	02/06/23	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		02/28/28	5 FXD	\$1,250	4.900%	110
369	02/13/23	Tucson Electric Power Co	Senior	A3/A-		04/15/53	30 FXD	\$375	5.500%	175
370	02/13/23	Consumers Energy Co	FMB	A1/A		05/15/33	10 FXD	\$700	4.625%	97
371	02/16/23	Exelon	Senior	Baa2/BBB		03/15/53	30 FXD	\$650	5.600%	170
372	02/16/23	Exelon	Senior	Baa2/BBB		03/15/33	10 FXD	\$850	5.300%	145
373	02/16/23	Exelon	Senior	Baa2/BBB		03/15/28	5 FXD	\$1,000	5.150%	112.5
374	02/21/23	Constellation Energy Generation LLC	Senior	Baa2/BBB		03/01/33	10 FXD	\$600	5.800%	185
375	02/21/23	Constellation Energy Generation LLC	Senior	Baa2/BBB		03/01/28	5 FXD	\$750	5.600%	143
376	02/21/23	Consolidated Edison Co of New York In	Senior	Baa1/A-		03/01/33	10 FXD	\$500	5.200%	125
377	02/21/23	CenterPoint Energy Resources Corp	Senior	A3/BBB+		03/01/33	10 FXD	\$600	5.400%	145
378	02/21/23	CenterPoint Energy Resources Corp	Senior	A3/BBB+		03/01/28	5 FXD	\$600	5.250%	115
379	02/22/23	NextEra Energy Capital Holdings Inc	Senior	Baa1/BBB+		03/01/25	2 FXD	\$2,500	6.051%	120
380	02/27/23	Union Electric Co	FMB	A2/A		03/15/53	30 FXD	\$500	5.450%	155
381	02/27/23	Southern California Edison Co	FMB	A2/A-		03/01/53	30 FXD	\$450	5.700%	180
382	02/27/23	Southern California Edison Co	FMB	A2/A-		03/01/28	5 FXD	\$750	5.300%	115
383	02/27/23	PPL Electric Utilities Corp	FMB	A1/A+		05/15/53	30 FXD	\$750	5.250%	145
384	02/27/23	PPL Electric Utilities Corp	FMB	A1/A+		05/15/33	10 FXD	\$600	5.000%	120
385	02/27/23	DTE Electric Co	FMB	Aa3/A		04/01/53	30 FXD	\$600	5.400%	148

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

Case No.: U-21534
Exhibit: A-18
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Witness: T. J. Lepczyk

Line No.	(a) Offer Date	(b) Issuer	(c) Credit Ratings			(f) Maturity	(g) Tenor	(h) Amount (\$MM)	(i) Coupon	(j) Spread
			Secured (?)	Moody's	S&P					
386	02/27/23	DTE Electric Co	FMB	Aa3/A		04/01/33	10 FXD	\$600	5.200%	130
387	02/27/23	American Electric Power	Senior	Baa2/BBB+		03/01/33	10 FXD	\$850	5.625%	175
388	02/28/23	Florida Power & Light Co	FMB	Aa2/A+		04/01/53	30 FXD	\$750	5.300%	140
389	02/28/23	Florida Power & Light Co	FMB	Aa2/A+		04/01/33	10 FXD	\$750	5.100%	120
390	02/28/23	Florida Power & Light Co	FMB	Aa2/A+		04/01/28	5 FXD	\$1,000	5.050%	90
391	03/01/23	KeySpan Gas East Corp	Senior	Baa1/BBB+		03/06/33	10 FXD	\$500	5.994%	200
392	03/01/23	Eversource Energy	Senior	Baa1/BBB+		03/01/28	5 FXD	\$750	5.450%	123
393	03/01/23	Edison	Jr Sub	Baa3/BB+		06/15/53	30NC5 FXD/FXD	\$500	8.125%	0.1
394	03/02/23	Northwest Natural Gas Co	FMB	A2/AA-		03/15/33	10 FXD	\$100	5.750%	170
395	03/02/23	NRG Energy	Senior Secured	Baa3/BBB-		03/15/33	10 FXD	\$740	7.000%	310
396	03/02/23	Black Hills	Senior	Baa2/BBB+		03/15/28	5 FXD	\$350	5.950%	170
397	03/06/23	San Diego Gas & Electric Co	FMB	A1/A		04/01/53	30 FXD	\$800	5.350%	150
398	03/06/23	Duke Energy Progress LLC	FMB	Aa3/A		03/15/53	30 FXD	\$500	5.350%	148
399	03/06/23	Duke Energy Progress LLC	FMB	Aa3/A		03/15/33	10 FXD	\$500	5.250%	128
400	03/07/23	Evergy Kansas Central Inc	FMB	A2/A		03/15/53	30 FXD	\$400	5.700%	185
401	03/08/23	System Energy Inc	FMB	Baa1/A		04/15/28	5 FXD	\$325	6.000%	255
402	03/09/23	Louisville Gas and Electric Co	FMB	A1/A		04/15/33	10 FXD	\$400	5.450%	155
403	03/09/23	Kentucky Utilities Co	FMB	A1/A		04/15/33	10 FXD	\$400	5.450%	155
404	03/09/23	Idaho Power Co	FMB	A2/A-		03/15/53	30 FXD	\$400	5.500%	170
405	03/09/23	AEP Transmission Co LLC	Senior	A2/A-		03/15/53	30 FXD	\$700	5.400%	157
406	03/20/23	Duke Energy Ohio Inc	FMB	A2/A		04/01/53	30 FXD	\$375	5.650%	200
407	03/20/23	Duke Energy Ohio Inc	FMB	A2/A		04/01/33	10 FXD	\$375	5.250%	175
408	03/20/23	CenterPoint Energy Houston Electric LL	FMB	A2/A		04/01/53	30 FXD	\$300	5.300%	165
409	03/20/23	CenterPoint Energy Houston Electric LL	FMB	A2/A		04/01/33	10 FXD	\$600	4.950%	150
410	03/21/23	Southwest Gas Corp	Senior	Baa1/BBB		03/23/28	5 FXD	\$300	5.450%	175
411	03/21/23	Oklahoma Gas and Electric Co	Senior	A3/A-		04/01/53	30 FXD	\$350	5.600%	190
412	03/21/23	Nisource	Senior	Baa2/BBB+		03/30/28	5 FXD	\$750	5.250%	155
413	03/21/23	Indiana Michigan Power Co	Senior	A3/A-		04/01/53	30 FXD	\$500	5.625%	190
414	03/21/23	Duke Energy Indiana LLC	FMB	Aa3/A		04/01/53	30 FXD	\$500	5.400%	170
415	03/23/23	Public Service Electric and Gas Co	Senior	A1/A		03/15/53	30 FXD	\$400	5.125%	142
416	03/23/23	Public Service Electric and Gas Co	Senior	A1/A		03/15/33	10 FXD	\$500	4.650%	122
417	03/27/23	Wisconsin Power and Light Co	Senior	A3/A		04/01/33	10 FXD	\$300	4.950%	145
418	03/27/23	Public Service Co of Colorado	FMB	A1/A		04/01/53	30 FXD	\$850	5.250%	155
419	03/28/23	Virginia Electric and Power Co	Senior	A2/BBB+		04/01/53	30 FXD	\$750	5.450%	175
420	03/28/23	Virginia Electric and Power Co	Senior	A2/BBB+		04/01/33	10 FXD	\$750	5.000%	150
421	03/28/23	Southwestern Electric Power Co	Senior	Baa2/A-		04/01/33	10 FXD	\$350	5.300%	178
422	03/28/23	Pennsylvania Electric Co	Senior	Baa1/BBB		03/30/26	3 FXD	\$300	5.150%	140
423	03/28/23	Pacific Gas and Electric Co	FMB	Baa3/BBB-		04/01/53	30 FXD	\$750	6.700%	295
424	03/28/23	Metropolitan Edison Co	Senior	A3/BBB		04/01/28	5 FXD	\$425	5.200%	160
425	04/03/23	Evergy Metro Inc	Senior	A2/A+		04/15/33	10 FXD	\$300	4.950%	153
426	04/04/23	WEC Energy Group Inc	Senior	Baa1/BBB+		01/09/26	3 FXD	\$350	4.750%	100
427	05/01/23	Northern States Power Co/MN	FMB	Aa3/A		05/15/53	30 FXD	\$800	5.100%	135
428	05/01/23	Georgia Power Co	Senior	Baa1/BBB+		05/17/33	10 FXD	\$1,000	4.950%	140
429	05/01/23	Georgia Power Co	Senior	Baa1/BBB+		05/16/28	5 FXD	\$750	4.650%	105
430	05/01/23	CenterPoint Energy Resources Corp	Senior	A3/BBB+		03/01/28	5 FXD	\$300	5.250%	100
431	05/08/23	Oncor Electric Delivery Co LLC	Senior Secured	A2/A+		NA	5 FXD	\$600	--	85
432	05/08/23	Oncor Electric Delivery Co LLC	Senior Secured	A2/A+		NA	30 FXD	\$400	--	145
433	05/08/23	Ohio Power Co	Senior	Baa1/A-		06/01/33	10 FXD	\$400	5.000%	155
434	05/08/23	Eversource Energy	Senior	Baa1/BBB+		05/15/26	3 FXD	\$450	4.750%	105
435	05/08/23	Eversource Energy	Senior	Baa1/BBB+		05/15/33	10 FXD	\$800	5.125%	162.5
436	05/08/23	Eversource Energy	Senior	Baa1/BBB+		03/01/28	5 FXD	\$550	5.450%	130
437	05/08/23	DTE Energy Co	Senior	Baa2/BBB		06/01/28	5 FXD	\$800	4.875%	140
438	05/08/23	Baltimore Gas and Electric Co	Senior	A3/A		06/01/53	30 FXD	\$700	5.400%	158
439	05/09/23	Entergy Mississippi LLC	FMB	A2/A		09/01/33	10 FXD	\$300	5.000%	148
440	05/10/23	Edison	Senior	Baa2/BBB-		11/15/28	6 FXD	\$600	5.250%	190

Michigan Public Service Commission
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			Secured (?)	Moody's	S&P					
441	05/15/23	Southern Co/The	Senior	Baa2/BBB		06/15/33	10 FXD	\$750	5.200%	173
442	05/15/23	Southern Co/The	Senior	Baa2/BBB		06/15/28	5 FXD	\$750	4.850%	143
443	05/15/23	Puget Sound Energy Inc	FMB	A2/A-		06/01/53	30 FXD	\$400	5.448%	160
444	05/15/23	PacifiCorp	FMB	A1/A+		05/15/54	31 FXD	\$1,200	5.500%	165
445	05/15/23	National Fuel Gas	Senior	Baa3/BBB-		10/01/26	3 FXD	\$300	5.500%	190
446	05/15/23	Florida Power & Light Co	Senior	A1/A		05/15/26	3 FXD	\$500	4.450%	80
447	05/15/23	Florida Power & Light Co	FMB	Aa2/A+		05/15/33	10 FXD	\$750	4.800%	130
448	05/15/23	Florida Power & Light Co	FMB	Aa2/A+		05/15/30	7 FXD	\$500	4.625%	115
449	05/15/23	Florida Power & Light Co	FMB	Aa2/A+		05/15/28	5 FXD	\$750	4.400%	95
450	05/15/23	AES Corp/The	Senior	Baa3/BBB-		06/01/28	5 FXD	\$900	5.400%	200
451	05/17/23	Southern California Gas Co	FMB	Aa2/A+		06/01/33	10 FXD	\$500	5.200%	165
452	05/17/23	Southern California Gas Co	FMB	Aa2/A+		06/01/53	30 FXD	\$500	5.750%	190
453	05/17/23	Southern California Edison Co	FMB	A2/A-		12/01/53	30 FXD	\$700	5.875%	200
454	05/17/23	Southern California Edison Co	FMB	A2/A-		06/01/26	3 FXD	\$400	4.900%	112.5
455	05/17/23	National Rural Utilities Cooperative Fin	Sub	A3/BBB		09/15/53	30NC5 FXD/FXD	\$300	7.125%	0.0715
456	05/17/23	ITC Holdings Corp	Senior	Baa2/BBB+		NA	4 FXD	\$300	--	135
457	05/17/23	ITC Holdings Corp	Senior	Baa2/BBB+		06/01/33	10 FXD	\$500	5.400%	185
458	05/17/23	Electricite de France SA	Senior	Baa1/BBB		05/23/53	30 FXD	\$1,000	6.900%	310
459	05/17/23	Electricite de France SA	Senior	Baa1/BBB		05/23/33	10 FXD	\$1,000	6.250%	270
460	05/17/23	Electricite de France SA	Senior	Baa1/BBB		05/23/28	5 FXD	\$1,000	5.700%	215
461	05/22/23	AEP Texas Inc	Senior	Baa2/A-		06/01/33	10 FXD	\$450	5.400%	172
462	05/23/23	Ameren Illinois Co	FMB	A1/A		06/01/33	10 FXD	\$500	4.950%	127
463	05/30/23	Nisource	Senior	Baa2/BBB+		06/30/33	10 FXD	\$450	5.400%	175
464	05/30/23	Nisource	Senior	Baa2/BBB+		03/30/28	5 FXD	\$300	5.250%	135
465	05/31/23	American Electric Power	Jr Sub	Baa3/BBB+		08/15/25	2 FXD	\$850	5.699%	155
466	06/01/23	Pacific Gas and Electric Co	FMB	Baa3/BBB-		06/15/33	10 FXD	\$1,150	6.400%	280
467	06/01/23	Pacific Gas and Electric Co	FMB	Baa3/BBB-		01/15/29	5 FXD	\$850	6.100%	240
468	06/01/23	Pacific Gas and Electric Co	FMB	Baa3/BBB-		01/15/53	30 FXD	\$500	6.750%	315
469	06/05/23	Piedmont Natural Gas Co Inc	Senior	A3/BBB+		06/15/33	10 FXD	\$350	5.400%	170
470	06/07/23	National Grid PLC	Senior	Baa2/BBB		06/12/33	10 FXD	\$800	5.809%	202
471	06/07/23	National Grid PLC	Senior	Baa2/BBB		06/12/28	5 FXD	\$700	5.602%	167
472	06/08/23	Palomino Funding Trust I	Senior	Baa3/BBB-		NA	5 FXD	\$450	--	337.5
473	06/08/23	Electricite de France SA	Jr Sub	Ba2/B+		12/31/99	PerpNC10 FXD/FXD	\$1,500	9.125%	0.09125
474	06/13/23	Duke Energy Carolinas LLC	FMB	Aa3/A		NA	30 FXD	\$500	4.875%	150
475	06/13/23	Duke Energy Carolinas LLC	Senior	Aa3/A		01/15/33	10 FXD	\$350	4.950%	130
476	06/15/23	PECO Energy Co	FMB	Aa3/A		06/15/33	10 FXD	\$575	4.900%	120
477	06/20/23	Sempra Energy	Senior	Baa2/BBB		08/01/33	10 FXD	\$700	5.500%	180
478	06/20/23	Sempra Energy	Senior	Baa2/BBB		08/01/26	3 FXD	\$550	5.400%	123
479	06/26/23	The Connecticut Light and Power Co	FMB	A1/A+		07/01/33	10 FXD	\$300	4.900%	120
480	06/26/23	National Rural Utilities Cooperative Fin	Senior	A2/A-		09/15/28	5 FXD	\$400	5.050%	110
481	06/27/23	Arizona Public Service Co	Senior	A3/BBB+		08/01/33	10 FXD	\$500	5.550%	180
482	07/17/23	Boston Gas Co	Senior	Baa1/BBB+		07/20/53	30 FXD	\$400	6.119%	218
483	07/31/23	Xcel Energy	Senior	Baa1/BBB+		08/15/33	10 FXD	\$800	5.450%	153
484	07/31/23	Consumers Energy Co	FMB	A1/A		02/15/29	5 FXD	\$500	4.900%	75
485	08/03/23	Public Service Electric and Gas Co	FMB	A1/A		08/01/53	30 FXD	\$400	5.450%	115
486	08/03/23	Public Service Electric and Gas Co	FMB	A1/A		08/01/33	10 FXD	\$500	5.200%	103

Michigan Public Service Commission
DTE Electric Company
Recent Utility Corporate Bond Issuances

Case No.: U-21534
Exhibit: A-18
Schedule: H2
Witness: T. J. Lepczyk

Line No.	(a) Offer Date	(b) Issuer	(c) Credit Ratings			(f) Maturity	(g) Tenor	(h) Amount (\$MM)	(i) Coupon	(j) Spread
			Secured (?)	Moody's	S&P					
487	08/03/23	New York State Electric & Gas Corp	Senior	Baa1/A-		08/15/33	10 FXD	\$400	5.850%	168
488	08/03/23	New York State Electric & Gas Corp	Senior	Baa1/A-		08/15/28	5 FXD	\$350	5.650%	140
489	08/07/23	San Diego Gas & Electric Co	FMB	A1/A		08/15/28	5 FXD	\$600	4.950%	90
490	08/08/23	Virginia Electric and Power Co	Senior	A2/BBB+		08/15/53	30 FXD	\$600	5.700%	150
491	08/08/23	Virginia Electric and Power Co	Senior	A2/BBB+		08/15/33	10 FXD	\$400	5.300%	128
492	08/08/23	Entergy Texas Inc	FMB	A3/A		09/01/53	30 FXD	\$350	5.800%	160
493	08/08/23	Centerpoint Energy	Senior	Baa2/BBB		08/10/26	3 FXD	\$400	5.250%	90
494	08/14/23	Entergy Arkansas LLC	FMB	A2/A		09/15/33	10 FXD	\$300	5.300%	120
495	08/15/23	Alexander Funding Trust II	Secured	Baa3/BBB-		NA	5 FXD	\$500	--	310
496	09/05/23	WEC Energy Group Inc	Senior	Baa1/BBB+		NA	3 FXD	\$600	--	93
497	09/05/23	The Southern Co	Senior	Baa2/BBB		03/15/34	10 FXD	\$700	5.700%	148
498	09/05/23	The Southern Co	Senior	Baa2/BBB		03/15/29	5 FXD	\$600	5.500%	113
499	09/05/23	MidAmerican Energy Co	FMB	Aa2/A+		09/15/54	31 FXD	\$1,000	5.850%	147
500	09/05/23	MidAmerican Energy Co	FMB	Aa2/A+		01/15/34	10 FXD	\$350	5.350%	110
501	09/05/23	Duke Energy	Senior	Baa2/BBB		09/15/53	30 FXD	\$750	6.100%	173
502	09/05/23	Duke Energy	Senior	Baa2/BBB		09/15/33	10 FXD	\$600	5.750%	150
503	09/06/23	Idaho Power Co	FMB	A2/A-		04/01/54	31 FXD	\$350	5.800%	150
504	09/06/23	Black Hills	Senior	Baa2/BBB+		05/15/34	10 FXD	\$450	6.150%	190
505	09/11/23	Southern Co Gas Capital Corp	Senior	Baa1/BBB+		09/15/33	10 FXD	\$500	5.750%	148
506	09/11/23	Nevada Power Co	Senior	A2/A+		03/15/54	30 FXD	\$500	6.000%	163
507	09/12/23	The Brooklyn Union Gas Co	Senior	Baa2/BBB+		NA	10 FXD	\$400	--	212
508	09/12/23	Monongahela Power Co	FMB	A3/A-		02/15/34	10 FXD	\$400	5.850%	160
509	09/13/23	Sierra Pacific Power Co	Senior	A2/A+		03/15/54	30 FXD	\$400	5.900%	160
510	09/13/23	CenterPoint Energy Houston Electric LL	Secured	A2/A		10/01/28	5 FXD	\$500	5.200%	85
511	09/18/23	Public Service Co of New Hampshire	FMB	A1/A+		10/01/33	10 FXD	\$300	5.350%	105
512	09/18/23	NSTAR Electric Co	Senior	A1/A		10/01/28	5 FXD	\$150	5.600%	115
513	09/18/23	Interstate Power and Light Co	Senior	Baa1/A-		10/15/33	10 FXD	\$300	5.700%	145
514	09/26/23	Southern California Edison	FMB	A2/A-		10/01/28	5 FXD	\$550	5.650%	105
515	09/26/23	Constellation Energy Generation LLC	Senior	Baa2/BBB		10/01/53	30 FXD	\$900	6.500%	180
516	09/26/23	Constellation Energy Generation LLC	Senior	Baa2/BBB		01/15/34	10 FXD	\$500	6.125%	158
517	10/02/23	Public Service Enterprise	Senior	Baa2/BBB		10/15/33	10 FXD	\$400	6.125%	150
518	10/02/23	Public Service Enterprise	Senior	Baa2/BBB		10/15/28	5 FXD	\$600	5.875%	120
519	10/04/23	Dominion Energy South Carolina Inc	FMB	A2/A		10/15/53	30 FXD	\$500	6.250%	140
520	10/05/23	Atmos Energy	Senior	A1/A-		11/15/53	30 FXD	\$500	6.200%	133
521	10/05/23	Atmos Energy	Senior	A1/A-		11/15/33	10 FXD	\$400	5.900%	120
522	10/30/23	National Rural Utilities Cooperative Fina	Senior	A2/A-		11/13/26	3 FXD	\$400	5.600%	73
523	11/06/23	PG&E	FMB	Baa3/BBB		03/15/34	10 FXD	\$800	6.950%	233
524	11/06/23	Duke Energy Florida LLC	FMB	A1/A		11/15/53	30 FXD	\$700	6.200%	142
525	11/06/23	Duke Energy Florida LLC	FMB	A1/A		11/15/33	10 FXD	\$600	5.875%	125
526	11/06/23	Alabama Power Co	Senior	A1/A-		11/15/33	10 FXD	\$300	5.850%	120
527	11/07/23	Alliant Energy Finance LLC	Senior	Baa2/BBB+		03/30/29	5 FXD	\$300	5.950%	147
528	11/08/23	Oncor Electric Delivery Co LLC	Senior Secured	A2/A+		11/15/33	10 FXD	\$800	5.650%	115
529	11/08/23	Kentucky Power Co	Senior	Baa3/BBB		11/15/33	10 FXD	\$375	7.000%	250
530	11/08/23	Eversource Energy	Senior	Baa2/BBB+		02/01/29	5 FXD	\$800	5.950%	147
531	11/08/23	Eergy Kansas Central Inc	FMB	A2/A+		11/15/33	10 FXD	\$300	5.900%	140
532	11/15/23	Ameren	Senior	Baa1/BBB		12/01/26	3 FXD	\$600	5.700%	105
533	11/16/23	SCE Trust VII	Pref	Baa3/BB+		12/31/99	1024 FXD	\$550	7.500%	7.5
534	11/20/23	Consolidated Edison Co of New York In	Senior	A3/A-		11/15/53	30 FXD	\$900	5.900%	137.5
535	11/20/23	Consolidated Edison Co of New York In	Senior	A3/A-		03/15/34	10 FXD	\$600	5.500%	115
536	11/28/23	Oglethorpe Power Corp	FMB	Baa1/BBB+		12/01/53	30 FXD	\$400	6.200%	175
537	12/04/23	Edison	Jr Sub	Baa3/BB+		06/15/54	31NC5 FXD/FXD	\$450	7.875%	0.07875
538	12/06/23	American Electric Power	Senior	Baa2/BBB+		01/15/29	5 FXD	\$1,000	5.200%	112.5
539	12/11/23	Vistra Operations Co LLC	Secured	Baa3/BBB-		10/15/33	10 FXD	\$400	6.950%	240
540	12/11/23	ONE Gas	Senior	A3/A-		04/01/29	5 FXD	\$300	5.100%	87
541	12/18/23	Ameren	Senior	Baa1/BBB		01/15/29	5 FXD	\$700	5.000%	110

Major Public Cellular reliability events

2/22/2024

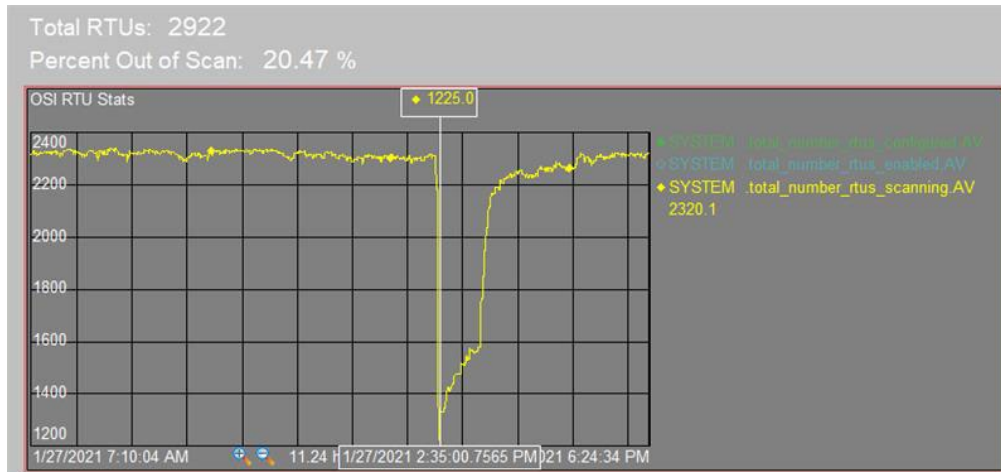
AT&T had a nationwide wireless (public cellular) service outage that impacted their customers in multiple cities for almost a day. This issue also impacted the AT&T FirstNet cellular service that is primarily built as a robust solution for dedicated use by “First Responders” such as DTE. Besides AT&T, many Verizon customers were also impacted due to their inter-dependencies with AT&T. While overall, DTEE experienced minimal impact due to this specific event, crews did have issues calling 911 dispatch. This highlights the potential for what could be an extremely disruptive impact if the scope of the cellular outage and time of remediation were not contained, or if it happened during a large storm.

7/26/2021

Public cellular systems were damaged and overloaded from a high volume of emergency calls due a tornado in the Commerce Lake and White Lake area. Loss of cellular communications in the area impacted restoration both through loss of communications to devices as well as impacted the coordination of restoration resources forcing crews to drive outside of the affected area to reestablish communications or use backup radio systems. Other localized cellular outages have impacted restoration and interrupted communications between crews and the control center, requiring DTE to fall back other radio systems and extending restoration times because crews and their supervisors have limited ability to contact critical resources directly.

1/27/2021

Carrier network configuration issue caused an unplanned loss of over one thousand SCADA RTUs which accounted for nearly half of all RTUs being scanned at the time of the outage. This resulted in hundreds of substations and pole top devices having no communication or control. There was a lengthy recovery period with no notification or communication of the outage. This event included several of our Critical 1 and Critical 2 RTUs like power plants, peakers, and wind parks.



There are also other public carrier events that occur to specific sites and this includes events that have impacted DTE service centers responsible for outage restoration as well as distribution, sub transmission and transmission stations, electrical stations at Powerplants and NERC critical assets. Some of the restorations to full capability took multiple days.

Statistics for 2023 are not available

	2022	2021
Outages total:	108	46
average duration	12 .5 hrs	12 hrs
Single carrier failure - multiple sites:	10	6

There is also significant impact to communications reliability that have occurred due to interference, unplanned maintenance and business decisions made by public carriers.

- Investment: AMI 3G/4G: AT&T was decommissioning their 3G network infrastructure in 2022, and given that nearly 1 million DTE's smart meters were dependent on AT&T's 3G for backhaul, DTE had to invest over \$36 million to remediate and install new network infrastructure in 2,700 cell relay locations to remove dependency on AT&T. While this transition was communicated, there was nothing technically wrong with the assets being replaced.
- Interference: Thumb Cellular: There has been multiple instances of DTE and Thumb Cellular experiencing interference from each other due spectrum being used by both DTE & Thumb Cellular. This conflict is due to Verizon network management policies.

- Unplanned maintenance: Impact to AMI Read Rate: Cellular Carriers select their maintenance windows based parameters that are not shared with or communicated to customers and irrespective of DTE's requirements. During midnight AMI meter interrogation, there are intermittent drops in that read-rate that are not seen during daytime hours (equating to tens of thousands to hundreds of thousands of meters). DTE's investigation concluded that it's highly likely due to the cellular carrier completing their schedule maintenance during that time slot. The midnight read rate is lower than the daytime read rate.
- 6GHz, 11GHz, 18GHz Microwave negatively impacted or rendered inoperable by FCC's decision to deregulate 6GHz to allow more public use: In some areas the interference from deregulated public and commercial use has rendered systems unable to operate or has degraded capability below what is needed for the microwave link to maintain its bandwidth. Microwave links were extensively utilized before the fiber program for backhaul of point to point communications between critical sites including power plants service centers and data centers.

Michigan Public Service Commission
DTE Electric Company
Telecom Cost

Case No. U-21534
Exhibit: A-19
Schedule: I1.2
Witness: S. M. Hartwick
Page: 1 of 1

Fiber bid sample comparison

	(a)	(b)	(c)	(d)	(e)
Line	Route	Miles	Low Bid \$/mile	High Bid \$/mile	Bid Savings/mile
1	Route 1	18.8	\$ 43,805	\$ 99,372	\$ 55,567
2	Route 2	51.3	\$ 48,728	\$ 75,354	\$ 26,626
3	Route 3	51.2	\$ 47,987	\$ 70,862	\$ 22,875
4	Route 4	17.3	\$ 37,970	\$ 46,806	\$ 8,836
5	Route 5	18.4	\$ 37,096	\$ 37,831	\$ 735
6	Route 6	13.6	\$ 40,805	\$ 43,165	\$ 2,360
7	Route 7	32.4	\$ 36,960	\$ 62,129	\$ 25,169
8	Route 8	13.0	\$ 36,960	\$ 74,633	\$ 37,673
9	Route 9	25.0	\$ 55,796	\$ 57,840	\$ 2,044
10	Route 10	31.5	\$ 24,411	\$ 30,413	\$ 6,002
11	Route 11	20.0	\$ 36,985	\$ 44,796	\$ 7,811

Michigan Public Service Commission

DTE Electric Company

Proposed Nuclear Surcharge

Projected Test Period - 12 Months Ending December 31, 2025

(\$000)

Case No.: U-21534

Exhibit: A-20

Schedule: J1

Witness: J. C. Davis

Page: 1 of 1

(a)		(b)	(c)		
Line No.	Description	Projected Test Period	Reference		
1	Proposed Nuclear Surcharge:				
2	Site Security & Radiation Protection	31,203	From Line 11, col. (h); Per U-14399 Order		
3	Nuclear Decommissioning Funding	2,867	U-21297 Exh A-20, Sch. J1		
4	Low Level Radioactive Waste Disposal Funding	6,000	Per U-10102 Order; U-21297 Exh. A-20, Sch. J1		
5	Proposed Nuclear Surcharge	40,070	Sum Lines 2 thru 4		
6	Current Authorized Nuclear Surcharge	38,909	Per U-21297 Order		
7	Change in Nuclear Surcharge	1,161	Line 5 less Line 6		
(d)		(e)	(f)	(g)	(h)
Description		2022 Historical 1/	2023	2024	Projected 12 mo. ending 12/31/25
8	Site Security & Radiation Protection:				
9	Site Security	16,549	17,079	17,574	18,084
10	Radiation Protection	12,006	12,390	12,749	13,119
11	Total Site Security & Radiation Protection	28,555	29,469	30,323	31,203
12	Annual Inflation Adjustment		3.20%	2.90%	2.90%
13	No. of Months in Period		12	12	12
14	Pro-rated Inflation Rate		3.20%	2.90%	2.90%

(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)

1/ Eliminated from Nuclear Power Base O&M expense - see Exh A-13, Sch C5.3, Col. (d)

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
Exhibit: A-20
Schedule: J2
Witness: J. C. Davis
Page: 1 of 28

Program:	Undervessel Replacements				
Purpose & Necessity:	The purpose of undervessel components goes to the heart of safely operating a nuclear reactor and directly affects control and monitoring of power levels throughout the reactor core (undervessel components are so named because the components are driven by equipment located underneath the reactor pressure vessel); unplanned or unrecoverable loss of these components would challenge plant operator’s ability to safely operate the Fermi 2 plant. Undervessel components include control rod drives and nuclear instrumentation such as local power range monitors (LPRMs). These components provide control and monitoring of power levels in the reactor.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 2				
Scope:	Replacement of undervessel components: control rod drive mechanisms and local power range monitors. Undervessel Replacement project closely relates to the Control Rod Drive Mechanism (CRDM) Replacements such that the CRDM are the expenditures to replace the internal components of the CRDM during the online cycle; Undervessel Replacements projects include the expenditures to physically go under the vessel and replace the CRDMs during the refueling outage.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; avoid a potential shutdown due to not meeting technical specification and licensing requirements.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X		X
Planned Completion Schedule:	Replaced 14 LPRMs in RF21 (2022) Projected to replace nine LPRMs in RF22 (2024)				

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
Exhibit: A-20
Schedule: J2
Witness: J. C. Davis
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Program:	Visual Annunciator System (VAS) Replacement				
Purpose & Necessity:	The purpose of the VAS is to provide visual and audible Control Room indications when abnormal conditions exist in the plant. It also maintains a printable Sequence of Events record, by recording the time that each alarm input was received and cleared. The Visual Annunciator System consists of a plant computer integration & display system that alerts operators in the Main Control Room (MCR) when a parameter or system condition is abnormal or requires action. The existing system was installed in 2002 and changes in technology and obsolescence challenged maintaining VAS reliability.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 3				
Scope:	Replacement of the Fermi 2 VAS including modification, installation and testing of computer processors, circuit cards, visual labeled annunciator tiles, pushbuttons and auditory devices to integrate with previously installed integrated plant computer system (IPCS).				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; unplanned or unrecoverable loss of the VAS or VAS components would challenge plant operator's ability to safely operate plant and require compensatory actions by plant operators including potential plant shutdown to meet regulatory requirements.				
Impact:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
		X	X		X
Planned Completion Schedule:	Visual Annunciator System project was completed in RF22 (2022)				

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
Exhibit: A-20
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Program:	Security System Computer				
Purpose & Necessity:	The security computer system itself is an aspect of the Fermi 2 Physical Security Plan (the exact details of physical security plans are safeguarded and protected per regulation) – having and maintaining Fermi 2’s security equipment in accordance with the approved physical security plan is a regulatory requirement and a condition to maintaining the Fermi 2 operating license. Because the consequences of hostile actors acting against a U.S. commercial nuclear plant are significant, each U.S. commercial nuclear site’s physical security plan is routinely inspected and tested by the NRC to ensure compliance. Repair and replacement of existing components has become increasingly difficult as equipment becomes obsolete. Components of the existing security system computer have exhibited decreased performance as service time has increased. Degradation of security equipment results in multiple alarms that distract the security force from core activities, requires compensatory measures which require unscheduled overtime, requires emergent maintenance, and increases the risk of gaps in meeting the regulatory requirements.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 4				
Scope:	• Replacement and modification of approximately 3,600’ of cable with fiber optic backbone in the Fermi 2 Protected Area and power block to support closed-circuit television (CCTV) • Replacement and modification of network computer system hardware, software, and cameras for currently installed Security Computer System (SCS) and Video Management Subsystem (VMS) • Replacement and modification of early warning intrusion detection system (IDS) which includes replacement of approximately 12,500’ of cabling • Replacement and modification of one of the three security uninterruptible power sources (UPS) • Install pre-access Secure Owner Controlled Area (SOCA) Building • Replacement and modification of perimeter intrusion detection (PID) microwave equipment				
Customer benefit/ Effect on cost of operation & reliability:	Continued compliance with NRC physical protection regulations. Equipment failures require compensatory measures which require unscheduled overtime, and increase the risk of gaps in meeting the regulatory requirements. This project also brings equipment and strategy up to nuclear industry standards and allow for more efficient equipment maintenance. Additionally, the project adds new equipment (ie additional cameras) and changes the location of some equipment which has the potential to reduce ongoing operating costs.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X		X	X
Planned Completion Schedule:	Security System Computer replacement project is projected to be complete in 2024				

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
Exhibit: A-20
Schedule: J2
Witness: J. C. Davis
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Program:	Plant Radio System				
Purpose & Necessity:	The plant radio system is a major system and an aspect of the regulatory-required Fermi 2 Physical Security Plan and the regulatory-required Fermi 2 Radiological Emergency Response Plan and has the purpose to be the primary means of communication for plant personnel including site security and fire brigade during operations and potential accident scenarios; loss of the plant radio system would degrade plant operators' ability to safely operate the Fermi 2 Power Plant. To address security and operations vulnerabilities replacement of the plant radio system is reasonable and prudent. Radio communications within the power plant uses an antenna system installed in the early 1980s, experiences a 90% signal loss between the base station and the distributed antennas and can transmit only the UHS frequency band. Addition of two radio frequency bands also allows DTE Electric to evaluate changes to the Fermi 2 Physical Security Plan, further improve Fermi 2's security posture and enhance security's communication capabilities with outside emergency responders such as the Michigan State Police; existing coax communications cabling did not have capacity to support the two additional frequency bands				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 5				
Scope:	Replacement and modification of the plant radio system distributed antenna system (16 antennae), communications cabling (approximately 5,800' of coax cable with fiber optic cable) and uninterruptible power supplies will improve plant radio signal fidelity throughout the plant and add two additional radio frequencies bands (VHS and 800 MHZ) within the power plant.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; improves the margins to meet regulatory performance specifically in the areas of the Radiological Emergency Response Plan and Physical Security Plan which could directly impact public safety in the event of an emergency at the station. The communication cabling replacement to fiber cable also supports Plant Wireless project.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:	X	X		X	
Planned Completion Schedule:	Plant Radio System replacement project is projected to complete in 2024				

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
Exhibit: A-20
Schedule: J2
Witness: J. C. Davis
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Program:	Residual Heat Removal (RHR) Service Water outlet valve (F068A/B) replacement				
Purpose & Necessity:	The RHRSW supplies water to the Reactor Pressure Vessel (RPV) in the Emergency Core Flooding Mode of RHR, Low Pressure Coolant Injection (LPCI). The RHRSW consists of 2 completely independent and redundant divisions with the exception of the two, 1/2 capacity RHR Reservoirs. The RHRSW HX outlet valves are 24” diameter motor-operated valves (MOVs) and maintain RHR temperature by modulating the flow of cooling RHRSW through the RHR Heat Exchanger. The existing two RHRSW HX outlet valves (noted as F068A and F068B) were original plant equipment and oversized for actual plant conditions experienced during plant startup, surveillance testing and plant shutdown. Cavitation over years of operation has resulted in unacceptable wear and vibration; unanticipated or unexpected failure of these valves would result in the loss of critical plant safety equipment and result in a plant outage.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 6				
Scope:	Original equipment RHRSW HX outlet valve replacement and modification to address wear and optimize ongoing plant operating conditions. Replacement and modification of the motor operator, install of 24”x16” reducers, elbows and modification of piping and pipe supports.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; reliable RHRSW HX outlet valve performance avoids potential plant shutdown due to progressive valve degradation				
Impact:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
		X	X		X
Planned Completion Schedule:	F068A (Division I safety system) was replaced during RF21 (2022) F068B (Division II safety system) is projected to be replaced in RF22 (2024)				

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
Exhibit: A-20
Schedule: J2
Witness: J. C. Davis
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Program:	Environmentally Qualified (EQ) Seal Replacement				
Purpose & Necessity:	The EQ seals provide separation and protection between rooms/equipment in the plant to support maintaining acceptable environmental conditions for each space. Environmental Qualification of the seal takes into account the environment (ie heat, moisture, etc) and age of the material. Select EQ seals had reached end of life (aging and obsolescence) and required replacement no later than RF21.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 7				
Scope:	Replace 66 EQ seals and associated limit switches				
Customer benefit/ Effect on cost of operation & reliability:	Maintain compliance with NRC regulations; failure to replace the EQ seals could have rendered Fermi 2 out of compliance with its NRC operating license.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X			X
Planned Completion Schedule:	The Environmentally Qualified (EQ) Seal Replacement project completed in RF21				

Michigan Public Service Commission
DTE Electric Company
Nuclear Plant Capital Project Detail – Routine & Small Projects

Case No.: U-21534
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Program:	Safety Relief Valves (SRVs)				
Purpose & Necessity:	There are a total of 15 Safety Relief Valves located on the Main Steam (MS) piping exiting the Reactor Pressure Vessel (RPV). The purpose of these valves is to provide over pressurization protection for the RPV. Per ASME code: SRV pilots have an expected service life of approximately one cycle. SRV valve bodies have an expected service life of approximately four cycles.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 8				
Scope:	Replacement of the SRV pilot IBAD (platinum) coating of SRV pilots is performed offsite by a specialty supplier that maintains the specialized nuclear qualifications and inventory of nuclear-quality components necessary for the safe and reliable function of SRVs. Replace SRV pilots and valve bodies per schedule				
Customer benefit/ Effect on cost of operation & reliability:	Degradation or failure of SRVs require compensatory measures up to and including shutdown of the plant.				
Impact:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
		X	X		X
Planned Completion Schedule:	All 15 SRVs have their pilot valves replaced each refueling outage Replaced five SRV valve bodies in RF21 (2022) Project to replace four SRV valve bodies in RF22 (2024)				

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Program:	Snubber Replacements				
Purpose & Necessity:	Snubbers are dynamic shock absorbers (visually like a shock absorber on a vehicle) that are used to allow relatively slow movements of an attached component that are associated with thermal expansion, while providing rigid restraint against rapid motion due to dynamic loads such as seismic motion, water and steam hammer, and relief valve thrust loads. Snubbers are generally installed on almost all plant systems, both those that are important to safety as well as those secondary systems that are not. Fermi 2 has 648 snubbers its safety related systems and 54 snubbers on its non-safety related systems. The purpose of the snubber program at Fermi is to ensure snubber operability through visual inspections, functional testing, and service life monitoring. Snubbers are predominantly replaced based on service life, for functional testing of the existing snubber or for corrective maintenance.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 9				
Scope:	Internal snubber components are replaced and tested during online cycle operations to ready for replacement in upcoming refueling outage. Snubbers are replaced per schedule during refueling outage.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; snubbers protect components important to nuclear safety and reduce failures and the need for emergent repair or replacement of these components in the event they experience dynamic forces.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X	X	X
Planned Completion Schedule:	Replaced 170 snubbers in RF21 (2022) Project to replace 54 snubbers in RF22 (2024)				

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Program:	Unitized Actuators Replacement				
Purpose & Necessity:	Twenty-two individual hydraulic unitized actuator (UA) power units are provided for operating the 2 turbine bypass valves, 4 turbine stop valves, 4 turbine control valves, 6 intercept valves and 6 low pressure stop valves that provide for precise positioning of the turbine steam valves to modulate turbine output or isolate steam to the turbine as needed. The actuators are self-contained hydraulic power units mounted on the turbine valves. Periodic dismantled inspection and maintenance of UAs are required to address normal wear and tear as well as to support loss control standards and maintain safe and reliable operation. Replacement cycle for a UA is approximately every third refueling outage; therefore, leveled outage scope typically replaces seven or eight UAs each outage.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 11				
Scope:	Replace internal components within rotating spare UAs during cycle and have ready to use as replacements for upcoming refuel outage. Replace UAs during the refueling outage window.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; unexpected loss of a UA could require a power derate or shutdown to repair or replace. Performing UA maintenance per loss control standards ensures that the insurance requirements are maintained for turbine generator.				
Impact:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
			X		X
Planned Completion Schedule:	Replaced eight UAs in RF21 (2022) Project to replace seven UAs in RF22 (2024)				

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Program:	Residual Heat Removal (RHR) Motors				
Purpose & Necessity:	The purpose of Residual Heat Removal (RHR) is to remove decay heat from the reactor and containment. RHR is a closed-loop cooling system divided into 2 loops. Each loop consists of two 33-1/3% capacity single stage centrifugal pumps, a 100% capacity shell and tube heat exchanger, and associated piping and valves. Both loops are required to fully respond to a postulated accident scenario. There are 4 RHR pumps, 2 pumps per division. Each RHR pump has a large 2,250 HP motor and provides the motive force to cooling water. The RHR motors are limited by the environmentally qualified (EQ) life of their coatings. The four RHR motors require replacement with motors with qualified coatings to continue operations beyond RF23.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 12				
Scope:	Replace 4 RHR pump motors (2 per division)				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; delay in implementation of this project could result in violations and escalated regulatory engagement by the NRC.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X			X
Planned Completion Schedule:	Division II safety system RHR motors will be replaced in Refueling Outage 22 in Spring 2024 Division I safety system RHR motors will be replaced in Refueling Outage 23 in Spring 2026				

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Program:	High Pressure stop and control valves (HPSV/HPCV) replacement				
Purpose & Necessity:	The steam flow from the 52" manifold to the High Pressure (HP) turbine is controlled by four sets of Stop Valves (SV) and Control Valves (CV) - one set on each steam line. Periodic dismantled inspection and maintenance of HPSV/HPCVs are required to address normal wear and tear as well as to support loss control standards and maintain safe and reliable operation.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 13				
Scope:	Dismantled inspection and replacement of internal HPSV/HPCV components such as valve discs, seats, spindles and bearings. HPSVs are 29" diameter hydraulically-opened, spring-closed valves; HPCVs are 13" diameter hydraulically-opened, spring-closed valves				
Customer benefit/ Effect on cost of operation & reliability:	Maintains reliability of these components that could require a power derate or shutdown and ensures that the insurance requirements are maintained for turbine generator.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:			X		X
Planned Completion Schedule:	Dismantled and replaced internal components on two HPSVs and one HPCV in RF21 (2022) Project dismantle and replace internal components of two HPSV and one HPCV in RF22 (2024)				

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Program:	Reactor Recirculation System (RRS) Replacements				
Purpose & Necessity:	The purpose of the Reactor Recirculation System is to force coolant through the reactor core to cool the fuel at any power level and provide a means of changing coolant flowrate to control reactor power. The Reactor Recirc System has two external loops each consisting of a single stage, variable speed centrifugal pump driven by a 7,500 HP motor, suction and discharge gate valves, flow measuring element, controls and instrumentation, and associated piping. RRS pump seals are replaced every third refueling outage or based on operating experience and leakage trends; excess seal leakage could result in loss of reactor water inventory.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 14				
Scope:	Replace reactor recirculation pump mechanical seals on both the RRS pumps				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; avoid a potential shutdown due to not meeting technical specification and licensing requirements.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X		X
Planned Completion Schedule:	Replaced two RRS pump seal in RF21 (2022)				

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Program:	Main Steam Isolation Valve (MSIV) Replacement				
Purpose & Necessity:	The purpose of the Primary Containment Isolation System (PCIS) is to provide containment during a postulated accident scenario. Main steam isolation valves (MSIVs) are an aspect of the PCIS that prevent the excessive loss of reactor coolant from the reactor pressure vessel during a postulated accident scenario. Each of the four main steam (MS) lines has three isolation valves (MSIVs) - inboard (inside drywell), outboard (outside the drywell), and "third" MSIV (downstream of the outboard valve). The inboard and outboard MSIV are designed to close in a manner, which prevents nuclear release or exceeding mechanical limits on the MS piping. The third MSIV was installed for redundancy; it is not subject to routine replacement.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 15				
Scope:	Replace MSIV hydraulic operators, air manifolds or actuator springs of the four inboard MSIVs and the four outboard MSIVs. Replacement of these components is driven by environmental quality (EQ) requirements.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; avoids a potential shutdown due to not meeting technical specification and licensing requirements.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X		X
Planned Completion Schedule:	Replaced hydraulic operators, air manifolds and actuator springs on one inboard MSIV and one outboard MSIV in RF21 (2022) Project to replace the hydraulic operators, air manifolds and actuator springs on one inboard MSIV and one outboard MSIV in RF22 (2024)				

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Program:	Low Pressure stop and intercept valves (LPSV/LPIV) replacements				
Purpose & Necessity:	The Low Pressure Stop Valves (LPSV) and Low Pressure Intercept Valves (LPIV) control the reheated steam flow from the Moisture Separator Reheaters (MSRs) to low pressure (LP) turbines. There are a total of twelve valves, two on each line (two lines per MSR). Periodic dismantled inspection and maintenance of LPSV/LPIVs are required to address normal wear and tear as well as to support loss control standards and maintain safe and reliable operation.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 16				
Scope:	Dismantled inspection and replacement of internal LPSV/LPIV components such as valve discs, seats, spindles and bearings.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; unexpected loss of an LPSV or LPIV could require a power derate or shutdown. Performing LPSV/LPIV maintenance per loss control standards ensures that the insurance requirements are maintained for turbine generator.				
Impact:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
			X		X
Planned Completion Schedule:	Dismantled and replaced internal components on two LPSVs in RF21 (2022) Project to dismantle and replace internal components of one LPSVs and one LPIVs in RF22 (2024)				

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Program:	Valve Replacements				
Purpose & Necessity:	Fermi 2 systems contain approximately 20,000 valves of varying sizes, ratings, quality-assurance level, types and operators. Valves are monitored for leaks and mechanical degradation. Valves are cutout and replaced if repairs are not practical; for instance, a 2" valve is generally too small to replace only internal components - a complete replacement is the more practical field implementation practice.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 17				
Scope:	Replacement of valves				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; periodic valve maintenance and replacement support regulatory compliance and improve plant reliability.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X		X
Planned Completion Schedule:	Scope of valves identified each Refueling Outage.				

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Program:	Main Steam Bypass Valve (MSBV) Replacement				
Purpose & Necessity:	Turbine Bypass System, in conjunction with the Turbine Valves, maintain a nearly constant pressure in the Reactor. The MSBVs will open to dump steam to the Main Condenser if steam flow to the Turbine is not sufficient to maintain constant pressure, or the Turbine is off-line. The bypass valves fast-open on a Turbine trip to mitigate the pressure transient after the trip. The MSBVs can also be used for cooling down and depressurizing the reactor after shut down, or during postulated accident scenarios. Steam from the 52” manifold flows through two MSBVs to the main condenser. Periodic dismantled inspection and maintenance of MSBVs are required to address normal wear and tear as well as to support loss control standards and maintain safe and reliable operation.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 18				
Scope:	Dismantled inspection and replacement of internal MSBV components such as valve discs, seats, spindles and bearings. MSBVs are 12” diameter hydraulically-opened, spring-closed valves				
Customer benefit/ Effect on cost of operation & reliability:	Maintains reliability of these components that could require a power derate or shutdown and ensures that the insurance requirements are maintained for turbine generator.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:			X		X
Planned Completion Schedule:	Dismantled and replaced internal components on one MSBV in RF21 (2022) Project dismantle and replace internal components of zero MSBV in RF22 (2024)				

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Program:	Core Spray Line Vents				
Purpose & Necessity:	The purpose of the Core Spray System (CSS) is to provide reactor cooling water inventory makeup and spray cooling during a postulated accident scenario. CSS is divided into 2 divisions. Each division consists of two 50% capacity pumps, associated components and piping. CSS Keep Fill keeps the discharge header of CSS filled with water to prevent water hammer and decrease injection delay time to the RPV. CSS is filled and vented at high points in the system to remove air and non-condensable gases from the piping. All portions of the system are vented. To reduce likelihood of debris-induced fuel defects, certain evolutions during refueling outages require flushing and venting the CSS due to potential for debris to be transported directly to the reactor core. This plant operator activity has been historically performed by plant operators accessing ladders in a congested environment.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 19				
Scope:	Replacement and modification of core spray vent valves to floor level				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; improves both safety and confidence in completeness of flushing activities to mitigate nuclear fuel failures possibilities. Defect-free fuel supports most-efficient use fuel.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:	X		X		X
Planned Completion Schedule:	Division I safety system Core Spray Vents were completed in RF21 (2022) Division II safety system Core Spray Vents is projected to complete in RF22 (2024)				

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Program:	Control Rod Drive Mechanism (CRDM) Replacement				
Purpose & Necessity:	The control rod drive mechanism contains the mechanical parts needed to hold its associated control rod in place and drive it into and out of the reactor core. There are 185 CRDMs (one for each control rod) located at the bottom of the reactor pressure vessel. Each one of these drives works in conjunction with an associated hydraulic control unit. CRDMs function to support insertion of control rods which are used to maneuver the plant, shutdown the reactor and maintain it in a shutdown state when necessary; their function is essential in protecting the nuclear fuel from damage. CRDMs have an expected service life of approximately 9 cycles; therefore, considering their critically important function and using a proactive levelized replacement program, approximately 20 CRDMs are replaced each cycle.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 28				
Scope:	CRDM component replacement is performed on a subset of the CRDMs each refueling outage. CRDMs are radioactively contaminated equipment and require specialized shops to replace components safely. Fermi 2 CRDM component replacement is performed offsite by the Original Equipment Manufacturer (OEM). The OEM maintains the specialized nuclear qualifications and inventory of nuclear-quality CRDM components necessary for the safe and reliable function of CRDM.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; an online failure of any single CRDM (of the 185) requires a power reduction and failure of two or more requires a plant shutdown resulting in lost generation.				
Impact:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
		X	X		X
Planned Completion Schedule:	Twenty (20) CRDMs were replaced in Refueling Outage 21 in Spring 2022. Twenty (20) CRDMs are projected to be replaced in Refueling Outage 22 in Spring 2024.				

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Program:	General plant tools				
Purpose & Necessity:	General plant tools are those tools, equipment, computers that cost greater than \$1000, have a useful life greater than one year and are not permanently attached to the plant. The Fermi 2 Power Plant has metrology laboratories, chemistry laboratories, machine and fabricating shops, and tool cribs that have tooling and equipment that require periodic replacement; general plant tooling project supports those periodic replacements. Additionally Radiation Protection such as personal contamination monitoring stations and Security equipment such as x-ray machines require periodic replacement and general plant tooling project supports those periodic replacements.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 30				
Scope:	DTE Electric projects 2023 general plant project to include replacement of Security handheld radios, Radiation Protection whole body scanners (measures internal body dose levels), exit portal scanners (scanners monitor and detect persons exiting the Fermi 2 Radiologically Controlled Area for contamination), and radioactivity counters (measures levels of contamination), and metrology equipment. DTE Electric projects 2024 general plant project to include replacement of special tooling required to tension the reactor pressure vessel head, fire fighting equipment and security x-ray machines.				
Customer benefit/ Effect on cost of operation & reliability:	Provides tools and equipment Fermi 2 personnel use to perform activities at the plant as well as safeguard the health and safety of the public.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:	X	X	X	X	

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Planned Completion Schedule:	General plant project is placed into service annually as Fermi 2 receives the tools and equipment.

Program:	Plant Wireless System				
Purpose & Necessity:	The purpose of the plant wireless system is to provide wireless data communications capacity to plant personnel during normal operations; replacement, modification and expansion of the plant wireless system increasingly supports operations to effectively operate the plant. In addition, the Plant Wireless project is resource-optimized with the Plant Radio System replacement project by sharing the conduit and cable trays. Installation of a wireless communication backbone throughout the nuclear power block directly impacts the ability to progress with other cost-savings and radiological dose-savings initiatives including Electronic Work Orders, Electronic Operator Rounds, remote dose monitoring and remote equipment monitoring. NRC regulations require management measures which include configuration management, maintenance, training and certification, procedures, records management, and other quality assurance methods, generally on a continuing basis, that are applied to items relied on for safety, to ensure the items are available and reliable to perform their functions when needed. Plant wireless system provides the networking infrastructure and capacity necessary for Fermi 2 to modernize and maintain these management measures.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 35				
Scope:	The Plant Wireless System project modifies the plant to install 120V outlets and a network switch at each radio antenna location on site. Coordination with the Plant Radio project allowed efficiencies in cable routing resulting an overall reduction in capital expenditures.				
Customer benefit/ Effect on cost of operation & reliability:	This project directly impacts the ability to progress with other cost-savings and radiological dose-savings initiatives including Electronic Work Orders, Electronic Operator Rounds, remote dose monitoring and remote equipment monitoring without the additional expenditures for modifying the plant for embedded hardwire cables.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:			X	X	X
Planned Completion Schedule:	Plant Wireless System project is projected to complete in 2024				

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Program:	Hot machine shop				
Purpose & Necessity:	The Fermi 2 hot machine shop is a machining and testing shop specifically designed to accommodate contaminated (hot, radiologically speaking) plant components and equipment such as relief valves. The current Fermi 2 hot machine shop is located in the Turbine Building; most of the components and equipment that require use of the hot machine shop are located in the Reactor Building. The Hot Machine Shop project converts a previously-abandoned area of the Reactor Building into the Reactor Building hot machine shop.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 41				
Scope:	Converts a previously-abandoned room located on the third floor of the Reactor Building into a hot machine shop. Installation includes a design change to the Reactor Building HVAC, electrical, station air and water demin systems to accommodate hot machine shop equipment such as a lithe, relief valve test stand, drill press and hydraulic press, a new Kelly-enclosure for segregation of work, new lighting, new welding receptacles and drains.				
Customer benefit/ Effect on cost of operation & reliability:	More efficient use of Fermi 2 resources and workspaces. Traversing between the Turbine Building and the Reactor Building requires either going through an airlock or cycling Turbine Building and Reactor Building doors (as the Reactor Building is maintained at negative relative pressure); locating a machine shop in the Reactor Building will reduce the travel time to machine components and equipment located inside the Reactor Building and also reduce stress on plant processes and systems designed to maintain the Reactor Building at negative relative pressures.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:	X	X		X	
Planned Completion Schedule:	Hot machine shop is projected to be complete in 2023				

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Program:	Piping Replacements				
Purpose & Necessity:	Fermi 2 systems contain approximately 20,000 valves of varying sizes, ratings, quality-assurance level, types and operators. Valves are monitored for leaks and mechanical degradation. Valves are cutout and replaced if repairs are not practical; for instance, a 2" valve is generally too small to replace only internal components - a complete replacement is the more practical field implementation practice.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 2, Line 43				
Scope:	Replacement of piping 2023: Piping replacements included the replacement of Reactor Recirculation System drain line pup piping. This piping was immediately outside the reactor pressure vessel with no means to isolate the piping from the fuel pool water; to isolate the pipe and perform maintenance, DTE Electric was required to shut down the Fermi 2 Power Plant to allow for reactor pressure vessel disassembly so that water plugs could be installed from the inside of the reactor pressure vessel and isolate the fuel pool water from the pipe while replacement occurred.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; periodic valve maintenance and replacement support regulatory compliance and improve plant reliability.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X		X
Planned Completion Schedule:	Scope of piping identified each Refueling Outage. 2023: Fermi 2 Outage 23-01 and the associated Reactor Recirculation System drain line piping complete in 2023				

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Program:	Reverse Osmosis System Replacement				
Purpose & Necessity:	The reverse osmosis (RO) system produces high-quality demineralized water from raw water. This high-quality demineralized water is then stored and used as makeup water for the reactor coolant system and auxiliary systems. The system flow rate is 50 gallons per minute. Repair and replacement of existing RO components has become increasingly difficult as equipment becomes obsolete; the existing RO system is over 25 years old. Components of the existing RO system have exhibited decreased performance as service time has increased. Unreliable RO system performance can stress reactor vessel internals, plant chemistry performance and radiological safety performance. Replacement of the system addresses aging, obsolescence and availability.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 47				
Scope:	Replace and modify the existing single-train RO system consisting of a pre-treatment skid, RO skid and post-treatment skid with a dual-train RO system				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; the high-quality demineralized water supports protecting the reactor vessel internals and fuel from corrosive agents generally present in non-RO water. Replacement RO system will mitigate plant actions to rent temporary RO systems to maintain the feed of high-quality demineralized water.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:			X	X	X
Planned Completion Schedule:	Reverse Osmosis System replacement is projected to complete in 2025				

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Program:	Roof Replacements				
Purpose & Necessity:	DTE Electric assessments of the 42 roofs at the plant site rated 9 of the 42 roofs in poor condition and 13 of the 42 roofs in fair condition. Poor roof conditions have contributed to numerous leaks causing damage to plant work spaces.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 51				
Scope:	Replaced of approximately 76,760 square feet of degraded roofs located at the Fermi 2 Office Building Annex (OBA), Office Service Building (OSB), and Warehouse A.				
Customer benefit/ Effect on cost of operation & reliability:	Roof replacement minimizes the potential for injuries, likelihood of human error, the spread of contamination and the generation of nuclear waste; injury to persons, damage to equipment or plant infrastructure, and remediation of radiological contaminants would require additional cost and resources to restore.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:	X			X	X
Planned Completion Schedule:	The three roofs listed above were replaced in 2023.				

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Program:	Neutron monitoring system replacements				
Purpose & Necessity:	The Fermi 2 neutron monitoring system measures neutron (NMS) flux in the reactor core during all phases of plant operations and provides plant trip signals to automatically shutdown the plant under certain circumstances as the NMS detects conditions in the reactor core that threaten the integrity of the nuclear fuel. The NMS consists of six major systems: 1) Source Range Monitoring (SRM) System, 2) Intermediate Range Monitoring (IRM) System, 3) Local Power Range Monitoring (LPRM) System, 4) Average Power Range Monitoring (APRM), 5) Rod Block Monitoring System and 6) Traversing In-core Probe (TIP) System. The Nuclear Instrumentation Project focuses on SRM and IRM components. The SRM System provides neutron flux information during the refueling, shutdown, start-up and low-level-flux operations of the plant and consists of four separate and independent channels which themselves consist of a miniature fission chamber detector, a detector drive assembly, a preamplifier and the necessary signal conditioning equipment (known as a drawer) to process the detector output for display and trip functions. The IRM System provides neutron flux information during start-up and low-level-flux operations (overlapping with the high-flux range of the SRMs) to neutron flux levels associated with approximately 35% power level. The IRM System consists of eight separate and independent channels which themselves consist of a miniature fission chamber detector, a detector drive assembly, a preamplifier and the necessary signal conditioning equipment (known as a drawer) to process the detector output for display and trip functions. The SRM and IRM preamplifiers and drawers are at end of life and are experiencing increased frequency of failures – which during refueling outages can stop the ability to move fuel until the units have been restored.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 52				
Scope:	Replace all four SRM pulse preamplifiers and drawers and all eight IRM pulse preamplifiers and drawers.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; failure of any two IRMs within the same safety division or any two SRMs would result in the loss of a safety division and the loss of the neutron monitoring system which would result in the loss of operators ability to monitor reactor power levels during refueling outages and plant shutdowns.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X	X		X
Planned Completion Schedule:	Replacements are projected to be complete in 2024.				

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Nuclear Plant Capital Project Detail – Routine & Small Projects

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Program:	Natural Draft Cooling Towers				
Purpose & Necessity:	The purpose of Circulating Water (CW) is to remove the heat rejected to the Main Condenser by the low pressure turbines exhaust steam. CW transfers the heat from the Main Condenser to the atmosphere via 2 natural draft Cooling Towers. Fermi 2 has two 50% capacity, hyperbolic, natural draft, concrete Cooling Towers. The towers are 400 feet high and 454 feet wide at the base. Each cooling tower is divided into 84 cooling bays. The towers are the cross flow type where air flow is perpendicular to the downward flow of water.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 59				
Scope:	Replace cooling tower structural components and cooling tower fill. The fill splash surface consists of a series of baffles, also called splash bars, which interrupt the circulating water as it gravity flows from the Cooling Tower hot water distribution basin to a cold water basin below. The splash bars serve to break up the falling water into a fine spray, allowing the heat in the circulating water to be transferred to the air. As the warmed air rises through the Cooling Tower shell, it is replaced with cooler, more dense air that enters the tower through the louvers.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; equipment condition of components of the Natural Draft Cooling Tower directly impact thermal plant efficiency on a continuous basis impacting actual electrical output of the plant.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:			X		X
Planned Completion Schedule:	Project to replace 22 bays of fill in 2025.				

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Nuclear Plant Capital Project Detail – Routine & Small Projects

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Program:	Document Management System Enhancements				
Purpose & Necessity:	NRC regulations require management measures which include configuration management, maintenance, training and certification, procedures, records management, and other quality assurance methods, generally on a continuing basis				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 60				
Scope:	Replace existing management measures with document management system which includes automated and paperless procedures, automated workflow of design modifications, and work management system integration.				
Customer benefit/ Effect on cost of operation & reliability:	Supports safe and reliable plant operations; Document management system replacements allows DTE Electric to evaluate changes to the Fermi 2 Document Management organization and improve Fermi 2's regulatory compliance margins with regards to records management, configuration management, procedure use and adherence and other quality assurance requirements.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:		X		X	
Planned Completion Schedule:	Document management system enhancements is projected to complete in 2026.				

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Nuclear Plant Capital Project Detail – Routine & Small Projects

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Program:	Remote Monitoring				
Purpose & Necessity:	The remote monitoring project entails the installation of sensors and development of monitoring capabilities beyond current installed indication to identify early degradation of key plant equipment in order to preclude emergent failures. Remote monitoring technology will also be used to transition from time-based preventative maintenance (standard in the nuclear industry) to condition-based maintenance.				
Line Number:	Exhibit A-12, Schedule B5.3, Page 3, Line 61				
Scope:	Install sensor and monitoring hardware and software to enable remote monitoring of plant equipment: Install sensors on flow-accelerated corrosion susceptible piping; sensors and software to trend and diagnose critical measurements of vibration, oil quality, temperature and pressure; install smart air operated and motor operated valve actuators and smart relays; install smart motor control centers; replace cycle isolation monitoring equipment; install dose field monitoring and remote radiation protection survey sensors.				
Customer benefit/ Effect on cost of operation & reliability:	Avoids emergent cost of key unplanned equipment failures which require emergent overtime and potentially require an unplanned plant shutdown. Transition to condition-based maintenance could extend intervals for performing maintenance and thus reduce long-term maintenance costs.				
Impact Dimension:	Industrial Safety	Regulatory Compliance/Nuclear Safety	Reliability	O&M Avoidance	Asset Management
Targeted:			X	X	X
Planned Completion Schedule:	Remote Monitoring project is projected to be complete in 2026				

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Michigan Public Service Commission
DTE Electric Company
2023 Annual Incentive Plan and Rewarding Employees Plan Metrics:
DTE Electric Company

Case No.: U-21534
Exhibit: A-21
Schedule: K2
Witness: M. S. Cooper
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Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)
No.	Category	Measure	Weight		Threshold	Target	Maximum
			AIP	REP			
1	Financial Performance						
2		DTE Electric Operating Earnings	15.00%	15.00%	\$990	\$1,010	\$1,030
3							
4		DTE Electric Cash From Operations	15.00%	15.00%	\$2,113	\$2,348	\$2,583
5							
6		DTE Energy Operating Earnings Per Share	10.00%	10.00%	\$6.10	\$6.25	\$6.40
7							
8	Total Financial Measures		40.00%	40.00%			
9							
10	Customer Satisfaction						
11		Net Promoter Score	12.00%	12.00%	35	39	43
12							
13		MPSC Customer Complaints	8.00%	8.00%	2,008	1,912	1,816
14							
15	Total Customer Satisfaction Measures		20.00%	20.00%			
16							
17	Safety & Engagement						
18		DTE Electric Employee Engagement-Gallup	5.00%		4.17	4.26	4.45
19							
20		DTE Electric OSHA Recordable Incident Rate	5.00%	10.00%	0.71	0.57	0.48
21							
22		DTE Energy High Energy Serious Injury or Fatality	5.00%	5.00%	4	0	0
23							
24	Total Safety & Engagement Measures		15.00%	15.00%			
25							
26	Operating Excellence						
27		SAIDI Excluding Major Event Days	7.50%	7.50%	180	150	127
28							
29		Customers experiencing multiple interruptions (CEMI4%)	7.50%	7.50%	8.10%	7.55%	7.00%
30							
31		Generation Availability	5.00%	5.00%	79.8%	81.8%	83.8%
32							
33		Nuclear On-Line Reliability Loss Factor (ORLF)	5.00%	5.00%	1.45%	1.03%	0.61%
34							
35	Total Operating Excellence		25.00%	25.00%			
36							
37	Total Operating Measures		60.00%	60.00%			
38							
39	Total		100.00%	100.00%			

Michigan Public Service Commission
DTE Electric Company
2023 Annual Incentive Plan and Rewarding Employees Plan Metrics:
Nuclear Generation

Case No.: U-21534
Exhibit: A-21
Schedule: K3
Witness: M. S. Cooper
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Line No.	Category	Measure	Weight		Threshold	Target	Maximum
			AIP	REP			
1	Financial Performance						
2		DTE Electric Operating Earnings	5.00%	5.00%	\$990	\$1,010	\$1,030
3							
4		Nuclear Operations & Maintenance Expense	15.00%	15.00%	\$148	\$144	\$140
5							
6	Total Financial Measures		20.00%	20.00%			
7							
8	Safety & Engagement						
9		Nuclear Generation Employee Engagement-Gallup	5.00%		4.17	4.26	4.45
10							
11		Nuclear Total Industrial Safety Accident Events	5.00%	7.50%	1	0 in any Quarter	0 in all Quarters
12							
13							
14		DTE Electric OSHA Recordable Incident Rate	5.00%	7.50%	0.71	0.57	0.48
15							
16		On-Line Radiation Exposure	10.00%	10.00%	55.7	50.6	39.3
17							
18	Total Safety & Engagement Measures		25.00%	25.00%			
19							
20	Operating Excellence						
21		Nuclear On-Line Reliability Loss Factor (ORLF)	25.00%	25.00%	1.45%	1.03%	0.61%
22							
23		Nuclear Operational Focus	10.00%	10.00%	92.1	93.4	94.6
24							
25		Nuclear Annualized Work Management Index	10.00%	10.00%	99.6	99.8	100.0
26							
27		Nuclear Refuel Outage Milestone Completion	10.00%	10.00%	32 no more than 2 red	30 no more than 4 white	34 green
28							
29							
30	Total Operating Excellence		55.00%	55.00%			
31							
32	Total Operating Measures		80.00%	80.00%			
33							
34	Total		100.00%	100.00%			