



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

Estella R. Branson
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(313) 235-6985

September 12, 2024

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-21534

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-21 thru A-23, Schedules M1-M8

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 12:22:12 -04'00'

Estella R. Branson
Senior Paralegal

Enclosure

Case No.: U-21534
Exhibit: A-21
Schedule: K1
Witness: M. A. Fix
Page: 1 of 1

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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. A. Fix
Page: 1 of 1

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)
No.	Category	Measure	Weight		Threshold	Target	Maximum
1	Financial Performance		<u>AIP</u>	<u>REP</u>			
2		DTE Electric 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	2	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. A. Fix
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line			Weight				
No.	Category	Measure	AIP	REP	Threshold	Target	Maximum
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%			

Michigan Public Service Commission
DTE Electric Company
2023 Annual Incentive Plan and Rewarding Employees Plan Metrics:
DTE Energy Corporate Services LLC

Case No.: U-21534
Exhibit: A-21
Schedule: K4
Witness: M. A. Fix
Page: 1 of 1

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)
No.	Category	Measure	Weight		Threshold	Target	Maximum
1	Financial Performance		<u>AIP</u>	<u>REP</u>			
2		DTE Energy Operating Earnings Per Share	20.00%	20.00%	\$6.10	\$6.25	\$6.40
3							
4		DTE Energy Cash From Operations	20.00%	20.00%	\$2,746	\$3,051	\$3,356
5							
6	Total Financial Measures		40.00%	40.00%			
7							
8	Customer Satisfaction						
9		Net Promoter Score	12.00%	12.00%	35	39	43
10							
11		MPSC Customer Complaints	8.00%	8.00%	2,008	1,912	1,816
12							
13	Total Customer Satisfaction Measures		20.00%	20.00%			
14							
15	Safety & Er		6.1				
16		DTE Energy Employee Engagement-Gallup	5.00%		4.17	4.26	4.45
17							
18		DTE Energy OSHA Recordable Incident Rate	5.00%	10.00%	0.68	0.55	0.42
19							
20		DTE Energy High Energy Serious Injury or Fatality	5.00%	5.00%	4	2	0
21							
22	Total Safety & Engagement Measures		15.00%	15.00%			
23							
24	Operating Excellence:Electric						
25		Customers experiencing multiple interruptions (CEMI4%	6.25%	6.25%	8.10%	7.55%	7.00%
26							
27		SAIDI Excluding Major Event Days	6.25%	6.25%	180	150	127
28							
29		Nuclear On-Line Reliability Loss Factor (ORLF)	12.50%	12.50%	1.45%	1.03%	0.61%
30							
31	Total Electric Operating Excellence		25.00%	25.00%			
32							
33	Total Operating Measures		60.00%	60.00%			
34							
35	Total		100.00%	100.00%			

Line No.	Description	Weight			Threshold	Target	Maximum
		DTE Electric	Nuclear Generation	DTE Energy Corporate Services LLC			
1	Total DTE Energy Shareholder Return vs. Pee	80%	80%	80%	25th Percentile	55th Percentile	80th Percentile
2	Three Year Cumulative Operating EPS	20%	20%	20%	Board Approved	Board Approved	Board Approved
3	Total	100%	100%	100%			

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		Long Term Incentive Plan			Annual Incentive Plan			Rewarding Employees Plan			Total Incentive Plans		
		Expense	Benefit	Net	Expense	Benefit	Net	Expense	Benefit	Net	Expense	Benefit	Net
1	Financial Performance												
2	Total DTE Energy Shareholder Return vs. Peer Group	16,326		16,326							16,326		16,326
3													
4	Three Year Cumulative Operating EPS	4,082		4,082							4,082		4,082
5													
6	Nuclear Operations & Maintenance Expense				69		69	629		629	698		698
7													
8	DTE Electric Operating Earnings				254		254	2,846		2,846	3,099		3,099
9													
10	DTE Electric Cash From Operations				231	(1,605)	(1,374)	2,636	(18,341)	(15,705)	2,866	(19,946)	(17,079)
11													
12	DTE Energy Operating Earnings per share				1,908		1,908	5,128		5,128	7,036		7,036
13													
14	DTE Energy Cash From Operations				1,754		1,754	3,371		3,371	5,125		5,125
15													
16	Total Financial Measures	20,408	0	20,408	4,215	(1,605)	2,610	14,609	(18,341)	(3,731)	39,232	(19,946)	19,286
17													
18													
19	Customer Satisfaction												
20	Net Promoter Score				873	(556)	317	2,636	(1,679)	957	3,509	(2,235)	1,274
21													
22	MPSC Customer Complaints				582	(7)	575	1,757	(22)	1,735	2,339	(29)	2,310
23													
24	Total Customer Satisfaction Measures				1,455	(563)	892	4,393	(1,701)	2,692	5,848	(2,264)	3,584
25													
26	Safety & Engagement												
27	Employee Engagement-Gallup				376	(11,886)	(11,510)	0	0	0	376	(11,886)	(11,510)
28													
29	OSHA Recordable Incident Rate				376	(209)	167	2,368	(1,318)	1,050	2,745	(1,527)	1,217
30													
31	DTE Energy High Energy Serious Injury or Fatality				364	(202)	161	1,098	(611)	487	1,462	(814)	648
32													
33	Nuclear Total Industrial Safety Accident Events				13	(7)	6	172	(96)	76	184	(103)	82
34													
35	Nuclear On-Line Radiation Exposure				25	(14)	11	229	(128)	102	254	(141)	113
36													
37	Total Employee Engagement Measures				1,154	(12,319)	(11,165)	3,867	(2,152)	1,715	5,021	(14,471)	(9,450)
38													
39	Operating Excellence												
40	SAIDI Excluding Major Event Days				444	(4,921)	(4,476)	1,493	(16,533)	(15,041)	1,937	(21,454)	(19,517)
41													
42	Customers experiencing multiple interruptions (CEMI4%)				465	(5,153)	(4,688)	1,493	(16,533)	(15,041)	1,958	(21,686)	(19,728)
43													
44	Generation Availability				63	0	63	480	0	480	543	0	543
45													
46	Nuclear On-Line Reliability Loss Factor				909	(4,515)	(3,606)	2,914	(14,474)	(11,560)	3,823	(18,989)	(15,166)
47													
48	Nuclear Operational Focus				25	(124)	(99)	355	(1,765)	(1,410)	380	(1,889)	(1,509)
49													
50	Nuclear Annualized Work Management Index				25	(124)	(99)	355	(1,765)	(1,410)	380	(1,889)	(1,509)
51													
52	Nuclear Refuel Outage Milestone Completion				25	(124)	(99)	355	(1,765)	(1,410)	380	(1,889)	(1,509)
53													
54	Total Operating Excellence				1,957	(14,961)	(13,005)	7,445	(52,835)	(45,390)	9,402	(67,796)	(58,395)
55													
56	Total Operating Measures	0	0	0	4,566	(27,844)	(23,278)	15,705	(56,688)	(40,982)	20,271	(84,532)	(64,261)
57													
58	Total	20,408	0	20,408	8,781	(29,449)	(20,668)	30,315	(75,028)	(44,714)	59,504	(104,478)	(44,974)

Michigan Public Service Commission
DTE Electric Company
Projected Value of Tree Trimming Surge Program
(\$000,000)

Case No.: U-20836
Exhibit: A-22 Revised
Schedule: L1
Witness: S. M. Hartwick
Page: 1 of 6

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
No.	Description		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Surge Program O&M Costs												
2	Maintenance and Staff		147.3	178.9	183.8	148.0	156.4	116.1	119.3	122.5	126.0	128.2	128.1
3	Herbicide		2.0	2.1	2.1	2.2	2.2	2.3	2.4	2.4	2.5	2.6	2.7
4	Reactive Maintainence Costs		19.0	16.2	15.0	8.9	7.4	7.7	8.2	8.5	8.8	8.8	8.9
5	Total Tree Trimming Program O&M		168.4	197.1	200.9	159.1	166.0	126.1	129.8	133.4	137.3	139.6	139.7
6	Credit to Regulatory Asset	In. 5 - In.17	(70.5)	(58.2)	(67.0)	(52.7)	(43.7)	-	-	-	-	-	-
7	Credit to Tree Trim Incremental Surge		-	(40.0)	(30.0)	-	-						
8	Total Tree Trimming Program Cost		97.9	98.9	103.9	106.4	122.3	126.1	129.8	133.4	137.3	139.6	139.7
9	Tree Trimming Storm O&M		15.0	15.0	13.2	11.2	10.0	10.5	11.1	11.6	12.0	12.0	12.2
10	Other DO Tree-related O&M		11.3	11.3	10.0	8.5	7.5	7.9	8.4	8.8	9.0	9.1	9.2
11	Total Surge Program-Related O&M		124.2	125.3	127.1	126.1	139.9	144.5	149.3	153.8	158.3	160.6	161.1
12	Surge Funding	-In. 6	70.5	58.2	67.0	52.7	43.7	-	-	-	-	-	-
13	Status Quo O&M Costs												
14	Maintenance and Staff		76.8	80.7	85.0	88.1	103.5	112.8	110.6	114.4	118.4	120.5	123.8
15	Herbicide		2.0	2.1	2.1	2.2	2.2	2.3	2.4	2.4	2.5	2.6	2.7
16	Reactive Maintainence Costs		19.0	16.2	16.8	16.1	16.6	17.1	16.9	16.6	16.4	16.5	16.9
17	Total Tree Trimming Program O&M		97.9	98.9	103.9	106.4	122.3	132.2	129.8	133.4	137.3	139.6	143.3
18	Total Tree Trimming Program Cost		97.9	98.9	103.9	106.4	122.3	132.2	129.8	133.4	137.3	139.6	143.3
19	Tree Trimming Storm O&M		15.0	15.0	15.7	16.3	17.1	17.6	17.5	17.4	17.5	17.7	18.1
20	Other DO Tree-related O&M		11.3	11.3	11.8	12.2	12.9	13.3	13.2	13.1	13.2	13.4	13.7
21	Total Status Quo-Related O&M		124.2	125.3	131.4	134.9	152.3	163.1	160.5	164.0	167.9	170.7	175.1
22	Total O&M Savings	In. 21 - In.11	-	-	4.3	8.8	12.5	18.5	11.2	10.2	9.7	10.0	14.0
23	Surge Program Capital Costs												
24	Tree Trim Reactive Capital		2.9	2.9	2.5	2.1	1.9	2.0	2.1	2.2	2.3	2.3	2.3
25	Tree Trim Storm Capital		17.2	17.2	15.1	12.8	11.4	12.0	12.7	13.3	13.7	13.8	13.9
26	Other DO Tree-related Capital		69.5	69.6	61.2	52.0	46.3	48.7	51.4	53.8	55.4	55.7	56.4
27	Total Surge Program-Related Capital		89.5	89.7	78.8	67.0	59.6	62.7	66.2	69.3	71.3	71.7	72.7
28	Status Quo Capital Costs												
29	Tree Trim Reactive Capital		2.9	2.9	3.0	3.1	3.3	3.4	3.3	3.3	3.3	3.4	3.5
30	Tree Trim Storm Capital		17.2	17.2	17.9	18.6	19.6	20.1	20.0	19.9	20.0	20.3	20.8
31	Other DO Tree-related Capital		69.5	69.6	72.5	75.3	79.2	81.5	80.9	80.6	80.9	82.2	84.0
32	Total Status Quo-Related Captial		89.5	89.7	93.4	97.0	102.1	105.0	104.3	103.9	104.2	105.9	108.2
33	Total Capital Savings	In. 32 - In.27	-	-	14.6	30.1	42.5	42.2	38.1	34.6	32.9	34.2	35.5

Michigan Public Service Commission
DTE Electric Company
Projected Value of Tree Trimming Surge Program
(\$000,000)

Case No.: U-20836
Exhibit: A-22 Revised
Schedule: L1
Witness: S. M. Hartwick
Page: 2 of 6

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
No.	Description		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	Surge Program O&M Costs												
2	Maintenance and Staff		131.9	135.3	139.2	141.5	141.2	145.4	149.1	153.9	157.0	156.2	161.7
3	Herbicide		2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.3	3.4	3.5	3.6
4	Reactive Maintainence Costs		9.2	9.5	9.7	10.0	10.3	10.6	10.9	11.2	11.6	11.9	12.2
5	Total Tree Trimming Program O&M		143.8	147.6	151.8	154.6	154.6	159.2	163.3	168.5	172.0	171.6	177.6
6	Credit to Regulatory Asset	In. 5 - In.17	-	-	-	-	-	-	-	-	-	-	-
7	Credit to Tree Trim Incremental Surge												
8	Total Tree Trimming Program Cost		143.8	147.6	151.8	154.6	154.6	159.2	163.3	168.5	172.0	171.6	177.6
9	Tree Trimming Storm O&M		12.5	12.9	13.3	13.6	14.0	14.5	14.9	15.3	15.7	16.2	16.7
10	Other DO Tree-related O&M		9.4	9.7	10.0	10.3	10.6	10.9	11.2	11.5	11.9	12.2	12.6
11	Total Surge Program-Related O&M		165.8	170.2	175.1	178.5	179.3	184.5	189.4	195.3	199.6	200.0	206.8
12	Surge Funding	-In. 6	-	-	-	-	-	-	-	-	-	-	-
13	Status Quo O&M Costs												
14	Maintenance and Staff		131.5	128.1	132.1	134.5	136.6	140.0	142.2	146.9	149.9	152.4	154.4
15	Herbicide		2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.3	3.4	3.5	3.6
16	Reactive Maintainence Costs		16.9	16.7	16.8	17.1	17.5	17.7	18.0	18.3	18.7	19.2	19.6
17	Total Tree Trimming Program O&M		151.1	147.6	151.8	154.6	157.2	160.9	163.4	168.5	172.0	175.1	177.6
18	Total Tree Trimming Program Cost		151.1	147.6	151.8	154.6	157.2	160.9	163.4	168.5	172.0	175.1	177.6
19	Tree Trimming Storm O&M		18.2	18.3	18.5	18.9	19.4	19.7	20.1	20.5	21.1	21.7	22.1
20	Other DO Tree-related O&M		13.7	13.8	14.0	14.3	14.6	14.9	15.1	15.5	15.9	16.3	16.6
21	Total Status Quo-Related O&M		183.0	179.6	184.3	187.8	191.3	195.4	198.6	204.5	209.0	213.2	216.4
22	Total O&M Savings	In. 21 - In.11	17.2	9.4	9.2	9.3	12.0	10.9	9.2	9.2	9.4	13.1	9.5
23	Surge Program Capital Costs												
24	Tree Trim Reactive Capital		2.4	2.5	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.1	3.2
25	Tree Trim Storm Capital		14.3	14.8	15.2	15.6	16.1	16.5	17.0	17.5	18.0	18.6	19.1
26	Other DO Tree-related Capital		58.0	59.7	61.5	63.2	65.1	67.0	68.9	70.9	73.0	75.1	77.2
27	Total Surge Program-Related Capital		74.8	76.9	79.2	81.5	83.8	86.3	88.8	91.3	94.0	96.7	99.5
28	Status Quo Capital Costs												
29	Tree Trim Reactive Capital		3.5	3.5	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.2
30	Tree Trim Storm Capital		20.9	20.9	21.2	21.7	22.2	22.6	23.0	23.5	24.2	24.8	25.3
31	Other DO Tree-related Capital		84.4	84.6	85.8	87.8	90.0	91.3	93.0	95.1	97.8	100.5	102.3
32	Total Status Quo-Related Captial		108.8	109.0	110.6	113.1	115.9	117.6	119.9	122.6	126.0	129.5	131.9
33	Total Capital Savings	In. 32 - In.27	34.0	32.0	31.4	31.6	32.1	31.4	31.1	31.2	32.0	32.8	32.3

Michigan Public Service Commission
DTE Electric Company
Projected Value of Tree Trimming Surge Program
(\$000,000)

Case No.: U-20836
Exhibit: A-22 Revised
Schedule: L1
Witness: K. M. Vangilder
Page: 3 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	<u>Regulatory Asset</u>												
2	Beginning Balance	(1)	118.6	189.1	215.9	251.5	272.9	285.2	203.0	152.3	101.5	50.8	-
3	Annual Deferral	pg. 1-2, ln. 6	70.5	58.2	67.0	52.7	43.7	-	-	-	-	-	-
4	Amortization 1/	ln. 20	-	(31.4)	(31.4)	(31.4)	(31.4)	(82.1)	(50.8)	(50.8)	(50.8)	(50.8)	-
5	Ending Balance		189.1	215.9	251.5	272.9	285.2	203.0	152.3	101.5	50.8	-	-
6	Deferred Tax Liability	- ln. 5 x ln. 11	(49.0)	(55.9)	(65.2)	(70.7)	(73.9)	(52.6)	(39.5)	(26.3)	(13.2)	-	-
7	Net Rate Base		140.1	160.0	186.4	202.2	211.3	150.4	112.8	75.2	37.6	-	-
8	Average Balance	(1)	114.0	150.0	173.2	194.3	206.7	180.9	131.6	94.0	56.4	18.8	-
9	Return on Permanent Capital	(2)	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%
10	Return on Deferral	ln. 8 x ln. 9	10.0	13.1	15.2	17.0	18.1	15.8	11.5	8.2	4.9	1.6	-
11	Tax Rate	(3)	25.9%										
12													
13	<u>Regulatory Asset Amortization (4)</u>												
14	U-21015 Securitization		-	(31.4)	(31.4)	(31.4)	(31.4)	(31.4)	-	-	-	-	-
15	2021		-	-	-	-	-	(6.4)	(6.4)	(6.4)	(6.4)	(6.4)	-
16	2022		-	-	-	-	-	(11.6)	(11.6)	(11.6)	(11.6)	(11.6)	-
17	2023		-	-	-	-	-	(13.4)	(13.4)	(13.4)	(13.4)	(13.4)	-
18	2024		-	-	-	-	-	(10.5)	(10.5)	(10.5)	(10.5)	(10.5)	-
19	2025		-	-	-	-	-	(8.7)	(8.7)	(8.7)	(8.7)	(8.7)	-
20	Total Amortization Expense		-	(31.4)	(31.4)	(31.4)	(31.4)	(82.1)	(50.8)	(50.8)	(50.8)	(50.8)	-

- (1) Beginning balances provided by Witness Hartwick
(2) Derived from permanent capital rates on Exh. A-14 Sch. D1 and adjusted to pre-tax using the conversion factors
(3) Composite tax rate provided by DTE Energy Tax Department
(4) Assumes 5-year amortization starting in 2026 for the un-securitized portion of 2021 and all subsequent spend.
5- year amortization of the \$156.9 million approved via the U-21015 order dated June 23, 2021 begins in 2022.

Michigan Public Service Commission
DTE Electric Company
Projected Value of Tree Trimming Surge Program
(\$000,000)

Case No.: U-20836
Exhibit: A-22 Revised
Schedule: L1
Witness: K. M. Vangilder
Page: 4 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	Regulatory Asset												
2	Beginning Balance	(1)	-	-	-	-	-	-	-	-	-	-	-
3	Annual Deferral	pg. 1-2, ln. 6	-	-	-	-	-	-	-	-	-	-	-
4	Amortization 1/	ln. 20	-	-	-	-	-	-	-	-	-	-	-
5	Ending Balance		-	-	-	-	-	-	-	-	-	-	-
6	Deferred Tax Liability	- ln. 5 x ln. 11	-	-	-	-	-	-	-	-	-	-	-
7	Net Rate Base		-	-	-	-	-	-	-	-	-	-	-
8	Average Balance	(1)	-	-	-	-	-	-	-	-	-	-	-
9	Return on Permanent Capital	(2)	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%	8.76%
10	Return on Deferral	ln. 8 x ln. 9	-	-	-	-	-	-	-	-	-	-	-
11	Tax Rate	(3)											
12													
13	Regulatory Asset Amortization (4)												
14	U-21015 Securitization		-	-	-	-	-	-	-	-	-	-	-
15	2021		-	-	-	-	-	-	-	-	-	-	-
16	2022		-	-	-	-	-	-	-	-	-	-	-
17	2023		-	-	-	-	-	-	-	-	-	-	-
18	2024		-	-	-	-	-	-	-	-	-	-	-
19	2025		-	-	-	-	-	-	-	-	-	-	-
20	Total Amortization Expense		-	-	-	-	-	-	-	-	-	-	-

(1) Beginning balances provided by Witness Hartwick
(2) Derived from permanent capital rates on Exh. A-14 Sch. D1 and adjusted to pre-tax using the conversion factors
(3) Composite tax rate provided by DTE Energy Tax Department
(4) Assumes 5-year amortization starting in 2026 for the un-securitized portion of 2021 and all subsequent spend.
5- year amortization of the \$156.9 million approved via the U-21015 order dated June 23, 2021 begins in 2022.

Michigan Public Service Commission
DTE Electric Company
Projected Value of Tree Trimming Surge Program
(\$000,000)

Case No.: U-20836
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Page: 5 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Rate Base Savings Calculation												
2	Beginning PP&E	(1)	10.7	10.3	9.8	23.7	52.2	91.5	129.0	160.6	187.3	210.9	234.4
3	Added	pg. 3-4, ln. 9	-	-	14.6	30.1	42.5	42.2	38.1	34.6	32.9	34.2	35.5
4	Depreciation	Depreciation Workpaper	(0.4)	(0.4)	(0.7)	(1.6)	(3.1)	(4.8)	(6.4)	(7.9)	(9.3)	(10.6)	(12.0)
5	Ending PP&E		10.3	9.8	23.7	52.2	91.5	129.0	160.6	187.3	210.9	234.4	258.0
6	Average PP&E	(ln. 2 + ln. 5)/2	10.5	10.1	16.8	37.9	71.8	110.3	144.8	173.9	199.1	222.7	246.2
7	Average DTL	Depreciation Workpaper	(0.1)	(0.2)	(0.2)	(0.4)	(0.9)	(1.6)	(2.5)	(3.6)	(4.8)	(6.1)	(7.4)
8	Average Rate Base		10.4	9.9	16.5	37.5	71.0	108.7	142.3	170.3	194.2	216.5	238.8
9	Revenue Requirement Savings												
10	Average Rate Base	ln. 8	10.4	9.9	16.5	37.5	71.0	108.7	142.3	170.3	194.2	216.5	238.8
11	Return on Permanent Capital	pg. 1-2, ln.	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%
12	Return on Rate Base	ln. 10 x ln. 11	0.9	0.9	1.4	3.3	6.2	9.5	12.5	14.9	17.0	19.0	20.9
13	Depreciation	ln. 4	0.4	0.4	0.7	1.6	3.1	4.8	6.4	7.9	9.3	10.6	12.0
14	O&M Savings	pg. 1-2, ln. 22	-	-	4.3	8.8	12.5	18.5	11.2	10.2	9.7	10.0	14.0
15	Property Taxes	Property Tax Workpaper	0.3	0.3	0.3	0.3	0.6	1.4	2.6	3.6	4.5	5.3	5.9
16	Cost Savings		1.6	1.6	6.7	14.0	22.4	34.3	32.6	36.6	40.4	44.9	52.9
17	Surge Expense	pg. 1-2, ln. ln. 5 - ln.17	(71)	(58)	(67)	(53)	(44)	-	-	-	-	-	-
18	Less Credit to Regulatory Asset	pg. 1-2, ln. 6	71	58	67	53	44	-	-	-	-	-	-
19	Revenue Requirement		1.6	1.6	6.7	14.0	22.4	34.3	32.6	36.6	40.4	44.9	52.9
20	Deferral Return	pg. 3-4, ln. 10	(10.0)	(13.1)	(15.2)	(17.0)	(18.1)	(15.8)	(11.5)	(8.2)	(4.9)	(1.6)	-
21	Deferral Amortization	pg. 3-4, ln. 20	-	(31.4)	(31.4)	(31.4)	(31.4)	(82.1)	(50.8)	(50.8)	(50.8)	(50.8)	-
22	Deferral Costs		(10.0)	(44.5)	(46.5)	(48.4)	(49.5)	(98.0)	(62.3)	(59.0)	(55.7)	(52.4)	-
23	Total Savings	ln. 19 + ln. 22	(8.4)	(42.9)	(39.8)	(34.4)	(27.1)	(63.7)	(29.7)	(22.4)	(15.3)	(7.5)	52.9
24	<u>Net Present Value of Program Savings</u>	(3)	<u>71.2</u>										
	Discount Rate	(2)	6.8%										

- (1) Beginning balances provided by Witness Hartwick
(2) Discount Rate provided by DTE Energy Regulatory Accounting
(3) NPV is calculated 2022-2042

Michigan Public Service Commission
DTE Electric Company
Projected Value of Tree Trimming Surge Program
(\$000,000)

Case No.: U-20836
Exhibit: A-22 Revised
Schedule: L1
Witness: K. M. Vangilder
Page: 6 of 6

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	Description		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	<u>Rate Base Savings Calculation</u>												
2	Beginning PP&E	(1)	258.0	278.5	295.8	311.1	325.4	338.9	350.4	360.4	369.2	377.5	385.3
3	Added	pg. 3-4, ln. 9	34.0	32.0	31.4	31.6	32.1	31.4	31.1	31.2	32.0	32.8	32.3
4	Depreciation	Depreciation Workpaper	(13.4)	(14.8)	(16.0)	(17.3)	(18.6)	(19.9)	(21.1)	(22.4)	(23.7)	(25.0)	(25.6)
5	Ending PP&E		278.5	295.8	311.1	325.4	338.9	350.4	360.4	369.2	377.5	385.3	392.0
6	Average PP&E	(ln. 2 + ln. 5)/2	268.2	287.2	303.5	318.3	332.2	344.7	355.4	364.8	373.3	381.4	388.6
7	Average DTL	Depreciation Workpaper	(8.7)	(10.1)	(11.4)	(12.8)	(14.2)	(15.6)	(17.1)	(18.5)	(19.9)	(21.3)	(22.7)
8	Average Rate Base		259.5	277.1	292.0	305.5	318.0	329.0	338.3	346.3	353.4	360.0	365.9
9	<u>Revenue Requirement Savings</u>												
10	Average Rate Base	ln. 8	259.5	277.1	292.0	305.5	318.0	329.0	338.3	346.3	353.4	360.0	365.9
11	Return on Permanent Capital	pg. 1-2, ln.	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%
12	Return on Rate Base	ln. 10 x ln. 11	22.7	24.3	25.6	26.8	27.9	28.8	29.6	30.3	31.0	31.5	32.1
13	Depreciation	ln. 4	13.4	14.8	16.0	17.3	18.6	19.9	21.1	22.4	23.7	25.0	25.6
14	O&M Savings	pg. 1-2, ln. 22	17.2	9.4	9.2	9.3	12.0	10.9	9.2	9.2	9.4	13.1	9.5
15	Property Taxes	Property Tax Workpaper	6.6	7.3	7.9	8.4	8.9	9.3	9.8	10.2	10.6	11.1	11.5
16	Cost Savings		60.0	55.7	58.7	61.7	67.3	68.9	69.7	72.1	74.7	80.7	78.8
17	Surge Expense	pg. 1-2, ln. ln. 5 - ln.17	-	-	-	-	-	-	-	-	-	-	-
18	Less Credit to Regulatory Asset	pg. 1-2, ln. 6	-	-	-	-	-	-	-	-	-	-	-
19	Revenue Requirement		60.0	55.7	58.7	61.7	67.3	68.9	69.7	72.1	74.7	80.7	78.8
20	Deferral Return	pg. 3-4, ln. 10	-	-	-	-	-	-	-	-	-	-	-
21	Deferral Amortization	pg. 3-4, ln. 20	-	-	-	-	-	-	-	-	-	-	-
22	Deferral Costs		-	-	-	-	-	-	-	-	-	-	-
23	Total Savings	ln. 19 + ln. 22	60.0	55.7	58.7	61.7	67.3	68.9	69.7	72.1	74.7	80.7	78.8
24	<u>Net Present Value of Program Savings</u>	(3)	71.2										
	Discount Rate	(2)	6.8%										

(1) Beginning balances provided by Witness Hartwick
(2) Discount Rate provided by DTE Energy Regulatory Accounting
(3) NPV is calculated 2022-2042

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 1 of 9

Line No.	Description	(a)	(b)	(c)	(c)	
		U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Percentage	
1	Base Capital Programs					
2	Emergent Replacements					
3	Storm	176,904	181,326	4,422	2%	
4	Non - Storm	265,214	263,014	(2,200)	-1%	
5	Substation Reactive	45,422	40,382	(5,040)	-11%	
6	Emergent Replacement Reduction Based on Strategic Spend	-	-	-	0%	
7	Subtotal Emergent Replacements	487,541	484,722	(2,819)	-1%	
8	Customer Connections, Relocations & Other					
9	Connections and New Load	217,753	214,093	(3,660)	-2%	
10	Relocations	26,124	22,776	(3,348)	-13%	
11	Electric System Equipment	31,984	30,180	(1,804)	-6%	
12	NRUC and Improvement Blankets	36,629	32,851	(3,778)	-10%	
13	General Plant, Tools & Equipment and Miscellaneous	7,528	8,103	576	8%	
14	Public Lighting Department Project	13,600	13,440	(160)		
15	Subtotal Customer Connections, Relocations & Other	333,617	321,443	(12,174)	-4%	
16	Customer Advances for Construction	(26,755)	(24,969)	1,787	-7%	
17	Total Base Capital Programs	794,403	781,196	(13,206)	-2%	
18						
19	Strategic Capital Programs					
20	Infrastructure Resilience and Hardening	384,109	418,440	34,331	9%	
21	Infrastructure Redesign and Modernization	162,735	173,059	10,324	6%	
22	Technology and Automation	98,276	123,441	25,164	26%	
23	Subtotal Strategic Capital Programs	645,120	714,939	69,819	11%	
25	Total Capital	1,439,523	1,496,136	56,613	4%	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 2 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Connections and New Load</u>				
2	Projected Small Load Growth Projects (Blanket)	14,981	18,236	3,256	
3					
4	Projected Customer Connections	129,249	123,726	(5,523)	
5	Projected Customer Connections CIAC	<u>(22,338)</u>	<u>(17,654)</u>	<u>4,683</u>	
6	Projected Customer Connections (Net of CIAC)	106,912	106,072	(840)	
7					
8	Projected New Business Projects	73,523	72,131	(1,392)	
9	Projected New Business Projects CIAC	<u>(2,758)</u>	<u>(5,151)</u>	<u>(2,393)</u>	
10	Projected New Business Projects (net of CIAC)	70,765	66,980	(3,786)	
11					
12	Incremental Infrastructure for EV	<u>-</u>	<u>-</u>	<u>-</u>	
13					
14	Total Connections and New Load	217,753	214,093	(3,660)	Less than forecasted customer demand in 2022
15	Total Connections and New Load CIAC	<u>(25,096)</u>	<u>(22,805)</u>	<u>2,290</u>	
16	Total Connections and New Load (Net of CIAC)	192,657	191,288	(1,369)	
17					
18	<u>Relocations</u>				
19	Projected Small Relocation Projects (Blanket)	9,521	8,439	(1,082)	
20					
21	Major Infrastructure Relocation Project				
22	Gordie Howe International Bridge	484	235	(249)	
23	I-375 Relocations	-	-	-	
24					
25	Relocation Projects (excl. Major Infrastructure Projects)	16,119	14,103	(2,016)	
26	Relocation Projects CIAC	<u>(1,660)</u>	<u>(2,163)</u>	<u>(503)</u>	
27	Subtotal Relocation Projects (Net of CIAC)	14,459	11,940	(2,519)	
28					
29	Total Relocations	26,124	22,776	(3,348)	
30	Total Relocations CIAC	<u>(1,660)</u>	<u>(2,163)</u>	<u>(503)</u>	
31	Total Relocations (Net of CIAC)	24,464	20,613	(3,851)	Less than forecasted customer demand in 2022
32					
33	Electric System Equipment				
34	Distribution Transformers & Regulators	8,991	9,027	37	
35	Projected Major Equipment	7,166	5,552	(1,614)	
36	Projected Meters	<u>15,827</u>	<u>15,601</u>	<u>(227)</u>	
37	Total Electric System Equipment	31,984	30,180	(1,804)	
38					
39	NRUC and Improvement Blankets				
40	Projected System Improvements	23,187	22,289	(897)	
41	Projected Normal Retirement Unit Changeouts (NRUC)	5,490	4,981	(509)	
42	Projected Operational Technologies	5,692	5,581	(112)	
43	Batteries and Chargers	2,254	-	(2,254)	Moved to the Resilience section - U-21534 Exhibit A-12, Schedule B5.4, pg. 13, Line 25
44	Animal Mitigation	<u>5</u>	<u>-</u>	<u>(5)</u>	
45	Total NRUC and Improvement Blankets	36,629	32,851	(3,778)	
46					

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 3 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
47	General Plant, Tools & Equipment and Miscellaneous				
48	Projected Substation Physical Security	724	655	(69)	
49	Projected General Plant, Tools & Equipment and Miscellaneous	6,803	7,448	645	
50	Total General Plant, Tools & Equipment and Miscellaneous	7,527	8,103	576	
51					
52	Public Lighting Department Project	13,600	13,440	(160)	
53					
54	Total Customer Connections, Relocations & Other	333,617	321,443	(12,174)	
55	Total Cust Connections, Relocations & Other CIAC	(26,755)	(24,968)	1,787	
56	Total Cust Connections, Relocations & Other Net of CIAC	306,862	296,475	(10,387)	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Resilience and Hardening
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 4 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Resilience and Hardening</u>				
2	Mobile Fleet Program	13,566	15,234	1,668	
3	Substation Risk: Drexel	1,915	1,898	(17)	
4	Substation Risk: Chestnut	161	64	(97)	
5	Substation Risk: Savage	562	577	15	
6	Substation Risk: Apache	3,381	4,653	1,272	
7	Substation Risk: Port Huron	184	184	(0)	
8	Substation Risk: Belleville Switchgear Decommission	1,206	1,234	27	
9	Substation Risk: McGraw	10,740	12,699	1,959	
10	Substation Risk: Voyager	200	201	1	
11	Substation Risk: Flood Defense Program	74	87	13	
12	4.8 kV Hardening	151,314	157,482	6,168	Company was able to complete more work than forecast
13	Pole and Pole Top Maintenance and Modernization (PTMM)	70,224	83,934	13,709	Company was able to complete more work than forecast
14	Cable Replacement Program	27,452	27,746	294	
15	Frequent Outage Program (CEMI)	55,597	60,067	4,469	Company was able to complete more circuits and additional scope per circuit
16	Breaker Replacement Program	13,576	14,415	839	
17	Pontiac Vaults	1,355	1,263	(92)	
18	URD Replacement Program	6,336	7,043	707	
19	URD Replacement Program: Detroit URD 1-1	1,061	1,154	93	
20	40 kV: Automatic Pole Top Switch	3,419	4,375	956	
21	Disconnect and Switcher Replacement	2,970	4,182	1,212	
22	Steel Pole Highway Crossings	1,935	1,880	(54)	
23	Station Upgrade: Warren (Relay Replacement)	3,183	271	(2,912)	Project was completed in 2021
24	Station Upgrade: Northeast (Relay Replacement)	12,494	13,279	785	
25	Batteries and Chargers Replacement Program	-	2,849	2,849	Moved from the New Load section (previously was under the NRUC and Improvement Blankets)
26	Substation Risk: Hood	-	-	-	
27	Substation Risk: UNVIL 301 B1 Conversion	-	-	-	
28	Portable Generators	-	-	-	
29					
30	Station Upgrade: Lincoln	-	-	-	
31	SCADA Pole Top Device Replacement	584	764	180	
32	Substation Regulator Replacement	422	685	262	
33	Station Upgrade: Navarre	-	-	-	
34	Station Upgrade: 120kV Relays Upgrade for ITC Projects	198	222	24	
35	Substation Risk: Savage Switchgear Replacement	-	-	-	
36	Substation Risk: Seville	-	-	-	
37	Substation Risk: Imlay	-	-	-	
38	Total Infrastructure Resilience and Hardening Projects and Programs	384,109	418,440	34,331	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 5 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Redesign and Modernization</u>				
2	Ann Arbor System Improvements: State Substation	6,004	5,996	(7)	
3	Ann Arbor System Improvements: Apex (Blue) Substation	3,489	3,484	(4)	
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	788	787	(1)	
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	887	1,947	1,060	
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	192	191	(0)	
7	Subtransmission Redesign & Rebuild: Trunk 7106	206	175	(31)	
8	Subtransmission Redesign & Rebuild: Trunk 2255	2,339	2,473	134	
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	1,051	1,174	123	
10	Subtransmission Redesign & Rebuild: Trunk 7333	1,229	1,300	72	
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	-	-	
12	Subtransmission Redesign & Rebuild: Boyne	14,185	14,072	(114)	
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1 2/	8,158	8,226	68	
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3 2/	2,392	3,262	869	
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4 2/	1,172	2,808	1,637	
16	Subtransmission Redesign & Rebuild: Tie 1568	47	64	17	
17	Subtransmission Redesign & Rebuild: Trunk 4217	300	331	30	
18	Subtransmission Redesign & Rebuild: Trunk 3509	159	126	(34)	
19	Subtransmission Redesign & Rebuild: Trunk 4266	17	3	(14)	
20	Subtransmission Redesign & Rebuild: Praxair	18	-	(18)	
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	4	-	(4)	
22	Subtransmission Breaker Short Circuit Violations	1,594	1,645	52	
23	Subtransmission Redesign & Rebuild: Slocum	698	125	(572)	
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	1,725	2,670	945	
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-	
26	TCHPP Switchyard Upgrades	-	-	-	
27	Trunk and Tie Lines Hardening Program: Prior Year's	-	(2)	(2)	
28	CODI: Charlotte Network Upgrade	8,286	8,319	33	
29	CODI: Targeted Network Secondary Cable Replacement	1,789	1,987	198	
30	CODI: Corktown Substation	1,360	1,352	(8)	
31	CODI: Islandview Substation - Phase 1 3/	10,118	12,255	2,137	Shifted project scope from 2023 forward to 2022
32	CODI: Islandview Substation - Phase 2 3/	2,774	3,176	402	
33	CODI: Islandview Substation - Phase 3 3/	20	45	25	
34	CODI: Midtown Substation Expansion	2,234	2,283	49	
35	CODI: Alfred Substation Expansion	53	63	10	
36	CODI: Howard Conversion	2	3	1	
37	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	387	241	(146)	
38	4.8 kV CC: Ariel Substation and Circuit Conversion	1,032	1,070	38	
39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade 4/	12,953	13,401	448	
40	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade 4/	1,556	2,043	487	
41	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	12,643	13,119	476	
42	4.8 kV CC: Buckler Circuit Conversion	8,136	8,889	753	
43	4.8 kV CC: McKinstry Sub Decommission	68	38	(31)	
44	4.8 kV CC: Quincy Conversion	1,021	1,052	31	
45	4.8 kV CC: Pinegrove Substation Relocation and Conversion	2,520	2,531	11	
46	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	-	-	-	
47	4.8 kV CC: Hawthorne Relief and Circuit Conversion	402	403	1	
48	4.8 kV CC: Crestwood Substation	23	25	1	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 6 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Notes 1/
49	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	2,638	2,603	(36)	
50	4.8 kV CC: Power line Conversion of MADSN 175L-W	123	107	(15)	
51	4.8 kV CC: GRFIN & WMSTN Conversions	508	136	(372)	
52	4.8kV CC: SCOTN	49	50	0	
53	4.8 kV CC: Slater	1,930	1,930	-	
54	4.8 kV CC: Royal Oak Substation and Circuit Conversion	-	-	-	
55	4.8 kV CC: Curtis	-	-	-	
56	4.8 kV CC: Unionville DC 301 B1 Conversion	-	-	-	
57	System Loading: Brest Substation	-	(2)	(2)	
58	System Loading: Carleton	376	336	(40)	
59	System Loading: Grayling	-	-	-	
60	System Loading: Prospect	-	(146)	(146)	
61	System Loading: Mandy 307 Load Transfer	24	1	(23)	
62	System Loading: Mack Transformer 102	54	32	(22)	
63	System Loading: Globe	-	-	-	
64	Pilot: Strategic and Service Undergrounding	454	462	7	
65	Pilot: Primary Deconductoring	1,848	1,846	(2)	
66	Subtransmission Redesign & Rebuild: Tie 810	9,100	8,832	(268)	
67	Subtransmission Redesign & Rebuild: Tie 7504	14	93	79	
68	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	2/ 945	896	(49)	
69	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	2/ 305	322	17	
70	Subtransmission Redesign & Rebuild: Trunk 2308	51	53	2	
71	Subtransmission Redesign & Rebuild: Tie 3205	17	96	79	
72	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	-	-	
73	Subtransmission Redesign & Rebuild: Tie 4104	106	134	28	
74	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	611	284	(326)	
75	Subtransmission Redesign & Rebuild: Trunk 4245	8	15	7	
76	Subtransmission Redesign & Rebuild: Trunk 4911	44	139	95	
77	Subtransmission Redesign & Rebuild: Custer Republic	-	-	-	
78	Subtransmission Redesign & Rebuild: Cortland Station Expansion	908	897	(11)	
79	CODI: CATO Substation Expansion	319	290	(28)	
80	CODI: Garfield Radial (Midtown Circuits)	5/ -	415	415	
81	CODI: Garfield Network Upgrade	5/ 18,193	17,430	(763)	
82	CODI: Kent/Gibson Conversion - Phase 1	6/ 2,051	2,186	135	
83	4.8 kV CC: Zenon Substation and Circuit Conversion	1	1	-	
84	4.8 kV CC: Calla Circuit Conversion and Phase 2	65	65	-	
85	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	2,710	2,728	18	
86	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	1	2	1	
87	4.8 kV CC: ISO Conversion Program	33	52	19	
88	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	-	-	-	
89	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	-	0	0	
90	8.3 kV CC: Pontiac Overhead Conversion	3,016	3,446	430	
91	8.3 kV CC: Pontiac Underground Conversion	702	747	45	
92	System Loading: Brown City	44	(28)	(73)	
93	System Loading: Port Sanilac	35	15	(20)	
94	System Loading: Richmond/Armada	1,164	3,201	2,037	Shifted purchase of substation transformer from 2023 to 2022
95	System Loading: Cody	-	-	-	
96	System Loading: Otsego/Capac/Shaw	-	-	-	
97	System Loading: Macomb/Golf	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 7 of 9

(a)		(b)	(c)	(c)	(d)
Line		U-21297 Forecast	U-21534 Forecast	Over / (Under)	
No.	Description	12 mos. ending 12/31/2022	12 mos. ending 12/31/2022	Forecast	Explanation 1/
98	System Loading: Grenada	185	225	40	
99	System Loading: Lark/Spruce	12	14	2	
100	System Loading: Jewell	-	-	-	
101	System Loading: Mayville	-	-	-	
102	System Loading: Goodison	-	-	-	
103	System Loading: Wixom	-	-	-	
104	System Loading: Diamond	-	-	-	
105	System Loading: Spokane/Seneca	-	-	-	
106	System Loading: Sterling	-	-	-	
107	System Loading: Disco	-	-	-	
108	System Loading: Tahoe	-	-	-	
109	System Loading: New Baltimore/Chesterfield	-	-	-	
110	System Loading: Kings Point	-	-	-	
111	Subtransmission Redesign & Rebuild: Tie 6907	-	-	-	
112	Subtransmission Redesign & Rebuild: Tie 6602	-	-	-	
113	Subtransmission Redesign & Rebuild: Trunk 2419	-	-	-	
114	Subtransmission Redesign & Rebuild: Kennett	-	-	-	
115	Subtransmission Redesign & Rebuild: Trunk 4601	-	-	-	
116	Subtransmission Redesign & Rebuild: Tempest Phase II	-	-	-	
117	Subtransmission Redesign & Rebuild: Waterman	-	-	-	
118	Subtransmission Redesign & Rebuild: Trunk 7105	-	-	-	
119	Subtransmission Redesign & Rebuild: Tie 5208	-	-	-	
120	4.8 kV CC: Hilton Substation and Circuit Conversion	-	-	-	
121	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	59	-	(59)	
122	4.8kV CC: Rochester Decommissioning and Tienken Relief	-	-	-	
123	4.8 kV CC: Ann Arbor AC Network Conversion	-	-	-	
124	4.8kV CC: Pittsfield Substation and Circuit Conversion	-	-	-	
125	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	-	-	-	
126	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	-	-	-	
127	Total Infrastructure Redesign and Modernization Projects and Programs	162,735	173,059	10,324	

1/ Variance greater than two million dollars are explained
2/ Tie 4105 phases on lines 13-15 and 68-69 were collectively "Subtransmission Redesign & Rebuild: Tie 4105" in U-21297 (Exh A-12, Sch B5.4, pg. 9, Line 17). Tie 4105 was forecasted at \$12,971 compared to actuals of \$15,514.
3/ CODI: Islandview Substation phases on lines 31-33 were collectively "CODI: Islandview Substation" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 45). Islandview was forecasted at \$12,912 compared to actuals of \$15,477.
4/ Promenade phases on lines 39-40 were collectively "4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 56). Promenade was forecasted at \$14,509 compared to actuals of 15,444.
5/ CODI: Garfield projects on lines 80-81 were collectively "CODI: Garfield Network Upgrade" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 50). CODI: Garfield was forecasted \$18,193 in U-21297 compared to \$17,845 in U-21534.
6/ CODI: Kent/Gibson Conversion - Phase 1 on line 82 was "CODI: Kent/Gibson Conversion" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 51).

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 8 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Technology and Automation</u>				
2	Distribution Automation	2/ 5,117	5,506	389	
3	ADMS: DMS/OMS	28,165	28,961	796	
4	SOC: ESOC	1,420	1,250	(170)	
5	SOC: ASOC	7,046	7,534	488	
6	Grid Automation Telecommunications	14,206	16,328	2,122	2023 scope pulled ahead to purchase material and prevent supply chain delays
7	Distribution Sensing and Monitoring (incldg Line Sensors)	1,523	862	(660)	
8	CVR/VVO	4,912	5,164	252	
9	NWA: O'Shea Energy Storage	1,067	1,456	389	
10	NWA: Battery Trailer	949	2,051	1,101	
11	NWA: Omega Load Relief	2,197	4,464	2,266	Specific battery trailer components and the associated labor for installation
12	NWA: Fisher Load Relief	77	66	(11)	
13	NWA: Port Austin Load Relief	598	619	21	
14	NWA: Small Solar and Storage Testbed	337	335	(3)	
15	Sensor, Network and Algorithm Development (Solar Deployment)	96	218	122	
16	Technology Programs & NWA	0	0	-	
17	AMI: Meter Communications Upgrades	626	631	5	
18	Customer Power Status Visibility	-	-	-	
19	SCADA Remote Access and Configuration Platform	453	1,164	711	
20	Substation Reporting and Process Enhancements	-	-	-	
21	Asset Management Upgrades	668	1,711	1,043	
22	Systematic Tracking of Rotatable Assets	-	-	-	
23	External Crew Efficiency	-	-	-	
24	Tree Trim Risk Prioritization Model	-	3,078	3,078	Investment was split between IT and DO. Further detailed provided by Company Witness Kryscynski
25	NWA: Veridian	387	360	(28)	
26	NWA: Adaptive Networked Microgrids	-	-	-	
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	-	-	
28	NWA: EV Charging Demonstration at ACM	1,231	1,292	60	
29	Interconnection Process Enablement	1,950	4,776	2,825	Timing of investment for interconnection gateway platform development moved ahead
30	Grid Edge Insights & New Technology	1,801	2,288	487	
31	DER Control	-	-	-	
32	ADMS Enhancements	-	-	-	
33	Operational Technology and Error Free Communication	5,898	5,496	(402)	
34	Meter Improvements	-	-	-	
35	FLISR Implementation	-	-	-	
36	DERMS	-	-	-	
37	Substation Cybersecurity	787	618	(170)	
38	Automation Configuration and Test Record Database	(43)	(115)	(72)	
39	Microwave End of Life	259	-	(259)	
40	Other Modernize Grid Management	4,772	7,807	3,036	See Witness Hartwick's testimony
41	ADMS: Network Management System	1,328	2,071	744	
42	Load Forecasting & Analytics	2,536	2,737	201	
43	Hosting Capacity Enablement	49	108	59	
44	Power Quality Analysis Program	-	-	-	
45	Substation Design Tool Upgrades	262	552	290	
46	Distribution Planning	-	932	932	
47	Enhance Maximo Capabilities and Processes	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 9 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Notes 1/
48	Primary Service Orders Replatform	-	-	-	
49	Work Management & Scheduling Upgrades	6,160	12,155	5,995	New tools supporting field and storm processes
50	Mobile tools expansion	-	-	-	
51	Maintain compliance	-	-	-	
52	Enhance and expand cybersecurity	-	-	-	
53	Mobile Equipment Replacement	-	-	-	
54	Mobile Technology	990	969	(21)	
55	SCADA / AMI Enhancements	450	-	(450)	
56	Total Technology and Automation Projects and Programs	98,276	123,441	25,164	

1/ Variance greater than two million dollars are explained
2/ Distribution Automation is collectively "Automation: Substation", "Automation: 13.2kV Circuit Distributions", and "4.8 kV Circuit Automation" in U-21297 (See Exh A-12, Sch B5.4, pg. 12 Line 9, 10, and 39, respectively)

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M2
Witness: A. J. Kryscynski
Page: 1 of 9

(a)		(b)	(c)	(c)	
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under)	
				Forecast	Percentage
1	Base Capital Programs				
2	Emergent Replacements				
3	Storm	220,576	281,848	61,272	28%
4	Non - Storm	183,074	207,192	24,118	13%
5	Substation Reactive	45,969	42,217	(3,752)	-8%
6	Emergent Replacement Reduction Based on Strategic Spend	(14,285)	-	14,285	-100%
7	Subtotal Emergent Replacements	435,335	531,257	95,922	22%
8	Customer Connections, Relocations & Other				
9	Connections and New Load	197,614	216,938	19,324	10%
10	Relocations	25,773	45,774	20,001	78%
11	Electric System Equipment	29,289	33,655	4,366	15%
12	NRUC and Improvement Blankets	22,401	19,531	(2,870)	-13%
13	General Plant, Tools & Equipment and Miscellaneous	6,622	5,886	(736)	-11%
14	Public Lighting Department Project	2,400	1,920	(480)	
15	Subtotal Customer Connections, Relocations & Other	284,099	323,703	39,605	14%
16	Customer Advances for Construction	(27,153)	(22,786)	4,367	-16%
17	Total Base Capital Programs	692,281	832,175	139,894	20%
13					
14	Strategic Capital Programs				
15	Infrastructure Resilience and Hardening	333,807	376,177	42,370	13%
16	Infrastructure Redesign and Modernization	341,094	259,244	(81,850)	-24%
17	Technology and Automation	136,604	165,605	29,001	21%
18	Subtotal Strategic Capital Programs	811,505	801,026	(10,479)	-1%
19					
20	Total Capital	1,503,786	1,633,201	129,415	9%

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 2 of 9

Line No.	(a) Description	(b) U-21297 Forecast 12 mos. ending 12/31/2023	(c) U-21534 Forecast 12 mos. ending 12/31/2023	(c) Over / (Under) Forecast	(d) Explanation 1/
1	<u>Connections and New Load</u>				
2	Projected Small Load Growth Projects (Blanket)	23,159	18,026	(5,133)	
3					
4	Projected Customer Connections	116,335	123,306	6,971	
5	Projected Customer Connections CIAC	<u>(16,598)</u>	<u>(16,782)</u>	<u>(184)</u>	
6	Projected Customer Connections (Net of CIAC)	99,737	106,524	6,787	
7					
8	Projected New Business Projects	58,120	75,606	17,486	
9	Projected New Business Projects CIAC	<u>(10,039)</u>	<u>(5,847)</u>	<u>4,192</u>	
10	Projected New Business Projects (net of CIAC)	48,081	69,759	21,678	
11					
12	Incremental Infrastructure for EV	<u>-</u>	<u>-</u>	<u>-</u>	
13					
14	Total Connections and New Load	197,614	216,938	19,324	
15	Total Connections and New Load CIAC	<u>(26,637)</u>	<u>(22,629)</u>	<u>4,008</u>	
16	Total Connections and New Load (Net of CIAC)	170,977	194,309	23,332	Higher than forecast customer demand in 2023
17					
18	<u>Relocations</u>				
19	Projected Small Relocation Projects (Blanket)	7,503	7,787	283	
20					
21	Major Infrastructure Relocation Project				
22	Gordie Howe International Bridge	-	-	-	
23	I-375 Relocations	-	5,938	5,938	New project requested by MDOT to relocate distribution infrastructure under I-375
24					
25	Relocation Projects (excl. Major Infrastructure Projects)	18,270	32,050	13,780	More work completed than forecast
26	Relocation Projects CIAC	<u>(516)</u>	<u>(157)</u>	<u>359</u>	
27	Subtotal Relocation Projects (Net of CIAC)	17,754	31,893	14,139	
28					
29	Total Relocations	25,773	45,774	20,001	
30	Total Relocations CIAC	<u>(516)</u>	<u>(157)</u>	<u>359</u>	
31	Total Relocations (Net of CIAC)	25,257	45,618	20,360	
32					
33	Electric System Equipment				
34	Distribution Transformers & Regulators	-	5,586	5,586	
35	Projected Major Equipment	14,534	12,748	(1,787)	
36	Projected Meters	<u>14,755</u>	<u>15,321</u>	<u>566</u>	
37	Total Electric System Equipment	29,289	33,655	4,366	
38					
39	NRUC and Improvement Blankets				
40	Projected System Improvements	10,387	7,797	(2,590)	
41	Projected Normal Retirement Unit Changeouts (NRUC)	6,096	4,432	(1,664)	
42	Projected Operational Technologies	<u>5,918</u>	<u>7,301</u>	<u>1,384</u>	
43	Total NRUC and Improvement Blankets	22,401	19,531	(2,870)	
44					
45	General Plant, Tools & Equipment and Miscellaneous				
46	Projected Substation Physical Security	536	544	9	
47	Projected General Plant, Tools & Equipment and Miscellaneous	<u>6,086</u>	<u>5,342</u>	<u>(744)</u>	
48	Total General Plant, Tools & Equipment and Miscellaneous	6,622	5,886	(736)	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 3 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
49					
50	Public Lighting Department Project	2,400	1,920	(480)	
51					
52	Total Customer Connections, Relocations & Other	284,099	323,703	39,604	
53	Total Cust Connections, Relocations & Other CIAC	(27,153)	(22,786)	4,367	
54	Total Cust Connections, Relocations & Other Net of CIAC	256,946	300,918	43,972	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Resilience and Hardening
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 4 of 9

Line No.	(a) Description	(b)	(c)	(c)	(d)
		U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Resilience and Hardening</u>				
2	Mobile Fleet Program	5,305	2,804	(2,501)	Delays in (1) obtaining materials and (2) rebuild unit work
3	Substation Risk: Drexel	268	640	373	
4	Substation Risk: Chestnut	3,715	989	(2,725)	Project delayed due to design
5	Substation Risk: Savage	2	11	9	
6	Substation Risk: Apache	11,628	8,492	(3,136)	Delay due to permit and obtaining circuit switchers
7	Substation Risk: Port Huron	-	3	3	
8	Substation Risk: Belleville Switchgear Decommission	1,006	1,313	308	
9	Substation Risk: McGraw	29,714	6,310	(23,405)	Land acquisition and design delays
10	Substation Risk: Voyager	-	2	2	
11	Substation Risk: Flood Defense Program	5,800	269	(5,531)	Delays due to design and vendor contract negotiations
12	4.8 kV Hardening	80,000	127,010	47,010	Company was able to complete more work than forecast
13	Pole and Pole Top Maintenance and Modernization (PTMM)	63,445	79,075	15,629	Company was able to complete more work than forecast
14	Cable Replacement Program	24,870	22,832	(2,039)	Delays due to safety hazards
15	Frequent Outage Program (CEMI)	55,252	63,963	8,711	More work completed in the Customer Excellence program
16	Breaker Replacement Program	13,177	13,161	(16)	
17	Pontiac Vaults	58	657	599	
18	URD Replacement Program	13,750	12,417	(1,333)	
19	URD Replacement Program: Detroit URD 1-1	-	285	285	
20	40 kV: Automatic Pole Top Switch	6,325	6,358	33	
21	Disconnect and Switcher Replacement	4,900	15,457	10,557	Trenton Channel Power Plant (\$2.7M) and River Rouge Power Plant (\$5.9) Switchyard Upgrades; Investment was include in U-21297 (Exh A-12, Sch B5.1, page 2, Line 32 and 37)
22	Steel Pole Highway Crossings	3,000	1,734	(1,266)	
23	Station Upgrade: Warren (Relay Replacement)	-	649	649	
24	Station Upgrade: Northeast (Relay Replacement)	2,417	3,652	1,235	
25	Batteries and Chargers Replacement Program	2,500	3,343	843	
26	Substation Risk: Hood	-	249	249	
27	Substation Risk: UNVIL 301 B1 Conversion	-	112	112	
28	Portable Generators	-	-	-	
29		-	-		
30	Station Upgrade: Lincoln	330	-	(330)	
31	SCADA Pole Top Device Replacement	1,611	1,694	83	
32	Substation Regulator Replacement	894	1,337	442	
33	Station Upgrade: Navarre	-	-	-	
34	Station Upgrade: 120kV Relays Upgrade for ITC Projects	3,839	1,359	(2,481)	Project deferrals requested by ITC, deferred to 2024
35	Substation Risk: Savage Switchgear Replacement	-	-	-	
36	Substation Risk: Seville	-	-	-	
37	Substation Risk: Imlay	-	-	-	
38	Total Infrastructure Resilience and Hardening Projects and Programs	333,807	376,177	42,370	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 5 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Redesign and Modernization</u>				
2	Ann Arbor System Improvements: State Substation	1,608	2,543	936	
3	Ann Arbor System Improvements: Apex (Blue) Substation	1,933	1,478	(455)	
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	7,920	334	(7,586)	Work dependent upon load transferring from Argo to new substation to commence this project scope
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	5,500	2,477	(3,023)	Projects shifted from 2023 to 2024 due to customer delays or inability to shutdown equipment to perform work
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	-	160	160	
7	Subtransmission Redesign & Rebuild: Trunk 7106	-	(90)	(90)	
8	Subtransmission Redesign & Rebuild: Trunk 2255	34	698	664	
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	-	207	207	
10	Subtransmission Redesign & Rebuild: Trunk 7333	-	168	168	
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	4,283	67	(4,216)	Clearance limitations complicated design and delays in developing shutdown plan
12	Subtransmission Redesign & Rebuild: Boyne	7,037	8,309	1,272	
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1 2/	1,271	1,448	177	
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3 2/	6,158	13,753	7,595	Increased scope and materials due to field conditions and co-location with Thumb Electric Co-op
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4 2/	1,941	-	(1,941)	
16	Subtransmission Redesign & Rebuild: Tie 1568	688	645	(43)	
17	Subtransmission Redesign & Rebuild: Trunk 4217	4,865	1,921	(2,944)	Project delayed due to material shortage and adjacent hazards in manholes
18	Subtransmission Redesign & Rebuild: Trunk 3509	1,184	2,284	1,099	
19	Subtransmission Redesign & Rebuild: Trunk 4266	270	-	(270)	
20	Subtransmission Redesign & Rebuild: Praxair	2,767	-	(2,767)	Project being re-designed and moved to 2025
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	34	4	(30)	
22	Subtransmission Breaker Short Circuit Violations	1,414	2,864	1,450	
23	Subtransmission Redesign & Rebuild: Slocum	737	511	(226)	
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	950	2,717	1,767	
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-	
26	TCHPP Switchyard Upgrades	-	2,334	2,334	
27	Trunk and Tie Lines Hardening Program: Prior Year's	-	-	-	
28	CODI: Charlotte Network Upgrade	6,658	8,727	2,069	Additional URD system conduit work, OH work shifted from 2022 to 2023 for cross arm design change
29	CODI: Targeted Network Secondary Cable Replacement	3,800	4,294	494	
30	CODI: Corktown Substation	-	100	100	
31	CODI: Islandview Substation - Phase 1 3/	7,027	7,734	707	
32	CODI: Islandview Substation - Phase 2 3/	27,363	35,847	8,484	Shifted pre-conversion overhead work from 2024 to 2023 and additional material required for secondary work
33	CODI: Islandview Substation - Phase 3 3/	1,355	-	(1,355)	
34	CODI: Midtown Substation Expansion	1,803	1,085	(717)	
35	CODI: Alfred Substation Expansion	4,137	3,183	(955)	
36	CODI: Howard Conversion	700	-	(700)	
37	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	-	737	737	
38	4.8 kV CC: Ariel Substation and Circuit Conversion	600	641	41	
39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade 4/	2,530	2,174	(356)	
40	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade 4/	5,662	4,204	(1,458)	
41	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	3,565	3,944	379	
42	4.8 kV CC: Buckler Circuit Conversion	2,865	3,882	1,018	
43	4.8 kV CC: McKinstry Sub Decommission	4,628	559	(4,069)	Construction delayed due to dependency for Waterman as built drawings
44	4.8 kV CC: Quincy Conversion	2,338	1,667	(670)	
45	4.8 kV CC: Pinegrove Substation Relocation and Conversion	43,760	20,626	(23,134)	Unidentified oil pipe in conduit route resulted in redesign, additional scope; delay in substation property
46	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	(15,300)	95	15,395	CIAC shifted from 2023 to 2024
47	4.8 kV CC: Hawthorne Relief and Circuit Conversion	6,000	-	(6,000)	U-21534 forecast is zero as project being considered for the IRM; Project scope reduced by 1/3
48	4.8 kV CC: Crestwood Substation	-	640	640	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 6 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Notes
49	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	3	25	21	
50	4.8 kV CC: Power line Conversion of MADSN 175L-W	238	578	340	
51	4.8 kV CC: GRFIN & WMSTN Conversions	4,145	2,218	(1,927)	
52	4.8kV CC: SCOTN	2,710	1,174	(1,536)	
53	4.8 kV CC: Slater	-	4	4	
54	4.8 kV CC: Royal Oak Substation and Circuit Conversion	2,000	652	(1,348)	
55	4.8 kV CC: Curtis	-	17	17	
56	4.8 kV CC: Unionville DC 301 B1 Conversion	-	-	-	
57	System Loading: Brest Substation	-	-	-	
58	System Loading: Carleton	28	187	159	
59	System Loading: Grayling	-	-	-	
60	System Loading: Prospect	-	-	-	
61	System Loading: Mandy 307 Load Transfer	-	(82)	(82)	
62	System Loading: Mack Transformer 102	8	10	2	
63	System Loading: Globe	500	-	(500)	
64	Pilot: Strategic and Service Undergrounding	2,100	3,830	1,730	
65	Pilot: Primary Deconductoring	-	36	36	
66	Subtransmission Redesign & Rebuild: Tie 810	20,000	21,771	1,771	
67	Subtransmission Redesign & Rebuild: Tie 7504	1,628	3,263	1,635	
68	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	2/ 10,542	-	(10,542)	U-21534 forecast is zero as project being considered for the IRM; Delayed due to property purchase
69	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	2/ 37	-	(37)	
70	Subtransmission Redesign & Rebuild: Trunk 2308	7,244	3,224	(4,020)	Design delayed due to change from contractor to internal resources; Construction stopped due to license delay
71	Subtransmission Redesign & Rebuild: Tie 3205	500	791	291	
72	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	-	-	
73	Subtransmission Redesign & Rebuild: Tie 4104	1,004	-	(1,004)	
74	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	7,820	1,677	(6,142)	Project being re-scoped; construction to start in late 2024
75	Subtransmission Redesign & Rebuild: Trunk 4245	3,059	703	(2,356)	Manhole and conduit inspections found collapse duct, construction delayed due to adjacent hazards
76	Subtransmission Redesign & Rebuild: Trunk 4911	894	-	(894)	
77	Subtransmission Redesign & Rebuild: Custer Republic	159	-	(159)	
78	Subtransmission Redesign & Rebuild: Cortland Station Expansion	343	40	(303)	
79	CODI: CATO Substation Expansion	10,795	3,139	(7,656)	Scope changes due to adjacent hazards and asbestos removal and additional relay design requirements
80	CODI: Garfield Radial (Midtown Circuits)	5/ 8,599	2,153	(6,446)	Refined design scope and estimate, which shifted construction start from 2023 to 2024
81	CODI: Garfield Network Upgrade	5/ 21,401	23,390	1,989	
82	CODI: Kent/Gibson Conversion - Phase 1	6/ 19,810	8,845	(10,965)	Easement and permit issues impacting design timeline and generator not needed
83	4.8 kV CC: Zenon Substation and Circuit Conversion	-	-	-	
84	4.8 kV CC: Calla Circuit Conversion and Phase 2	17	-	(17)	
85	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	8,682	947	(7,735)	Materials shifted to a project further along; Substation work shifted from 2023 to 2024
86	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	1,501	906	(595)	
87	4.8 kV CC: ISO Conversion Program	7,000	6,466	(534)	
88	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	158	152	(5)	
89	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	-	-	-	
90	8.3 kV CC: Pontiac Overhead Conversion	12,420	9,929	(2,491)	Road restoration lower than forecast
91	8.3 kV CC: Pontiac Underground Conversion	1,208	1,197	(11)	
92	System Loading: Brown City	4,685	2,485	(2,200)	Project was on hold due to customer easement dispute
93	System Loading: Port Sanilac	303	438	135	
94	System Loading: Richmond/Armada	6,351	8,417	2,066	Shifted purchase of substation transformer from 2023 to 2022
95	System Loading: Cody	461	384	(78)	
96	System Loading: Otsego/Capac/Shaw	396	151	(245)	
97	System Loading: Macomb/Golf	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 7 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Notes
98	System Loading: Grenada	2,105	3,521	1,416	
99	System Loading: Lark/Spruce	44	24	(20)	
100	System Loading: Jewell	-	1,265	1,265	
101	System Loading: Mayville	-	-	-	
102	System Loading: Goodison	-	-	-	
103	System Loading: Wixom	500	72	(428)	
104	System Loading: Diamond	-	-	-	
105	System Loading: Spokane/Seneca	116	62	(54)	
106	System Loading: Sterling	95	-	(95)	
107	System Loading: Disco	43	75	32	
108	System Loading: Tahoe	25	-	(25)	
109	System Loading: New Baltimore/Chesterfield	-	-	-	
110	System Loading: Kings Point	-	135	135	
111	Subtransmission Redesign & Rebuild: Tie 6907	426	-	(426)	
112	Subtransmission Redesign & Rebuild: Tie 6602	660	-	(660)	
113	Subtransmission Redesign & Rebuild: Trunk 2419	169	-	(169)	
114	Subtransmission Redesign & Rebuild: Kennett	437	-	(437)	
115	Subtransmission Redesign & Rebuild: Trunk 4601	214	-	(214)	
116	Subtransmission Redesign & Rebuild: Tempest Phase II	970	-	(970)	
117	Subtransmission Redesign & Rebuild: Waterman	103	-	(103)	
118	Subtransmission Redesign & Rebuild: Trunk 7105	61	-	(61)	
119	Subtransmission Redesign & Rebuild: Tie 5208	50	-	(50)	
120	4.8 kV CC: Hilton Substation and Circuit Conversion	-	-	-	
121	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	1,790	-	(1,790)	
122	4.8kV CC: Rochester Decommissioning and Tienken Relief	104	-	(104)	
123	4.8 kV CC: Ann Arbor AC Network Conversion	135	-	(135)	
124	4.8kV CC: Pittsfield Substation and Circuit Conversion	178	-	(178)	
125	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	269	-	(269)	
126	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	2,000	-	(2,000)	
127	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit 4/	1,418	-	(1,418)	
128	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Phase 4 4/	349	-	(349)	
129	Total Infrastructure Redesign and Modernization Projects and Programs	341,094	259,244	(81,850)	

1/ Variance greater than two million dollars are explained

2/ Tie 4105 phases on lines 13-15 and 68-69 were collectively "Subtransmission Redesign & Rebuild: Tie 4105" in U-21297 (Exh A-12, Sch B5.4, pg. 9, Line 17). Tie 4105 was forecasted at \$19,949 in U-21297 compared to \$15,201 in U-21534.

3/ CODI: Islandview Substation phases on lines 31-33 were collectively "CODI: Islandview Substation" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 45). Islandview was forecasted at \$35,745 in U-21297 compared to \$43,581 in U-21534.

4/ Promenade phases on lines 39-40 and 127-128 were collectively "4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 56). Promenade was forecasted at \$9,959 in U-21297 compared to \$6,378 in U-21534.

5/ CODI: Garfield projects on lines 80-81 were collectively "CODI: Garfield Network Upgrade" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 50). CODI: Garfield was forecasted \$30,000 in U-21297 compared to \$25,543 in U-21534.

6/ CODI: Kent/Gibson Conversion - Phase 1 on line 82 was "CODI: Kent/Gibson Conversion" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 51).

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Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Technology and Automation</u>				
2	Distribution Automation	2/ 23,042	27,104	4,063	Company was able to execute work at a faster pace then planned, scope was pulled ahead from 2024
3	ADMS: DMS/OMS	10,840	9,270	(1,570)	
4	SOC: ESOC	200	-	(200)	
5	SOC: ASOC	27,100	20,927	(6,173)	Technology and interior construction work will continue into the second quarter of 2024
6	Grid Automation Telecommunications	19,100	21,346	2,246	Scope was pulled ahead from 2024
7	Distribution Sensing and Monitoring (incldg Line Sensors)	-	6,552	6,552	398 UG and 100 OH sensors installed; 300 pole sensors and 1000 OH sensors purchased for 2024 installation
8	CVR/VVO	-	1,766	1,766	
9	NWA: O'Shea Energy Storage	350	889	539	
10	NWA: Battery Trailer	750	1,191	441	
11	NWA: Omega Load Relief	700	2,454	1,754	
12	NWA: Fisher Load Relief	1,350	180	(1,170)	
13	NWA: Port Austin Load Relief	4,282	3,627	(655)	
14	NWA: Small Solar and Storage Testbed	500	400	(100)	
15	Sensor, Network and Algorithm Development (Solar Deployment)	1,178	1,058	(120)	
16	Technology Programs & NWA	-	1	1	
17	AMI: Meter Communications Upgrades	-	-	-	
18	Customer Power Status Visibility	-	-	-	
19	SCADA Remote Access and Configuration Platform	500	607	107	
20	Substation Reporting and Process Enhancements	-	-	-	
21	Asset Management Upgrades	1,725	2,121	396	
22	Systematic Tracking of Rotatable Assets	-	-	-	
23	External Crew Efficiency	-	-	-	
24	Tree Trim Risk Prioritization Model	1,440	3,824	2,384	
25	NWA: Veridian	3,308	1,832	(1,476)	
26	NWA: Adaptive Networked Microgrids	-	17	17	
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	-	-	
28	NWA: EV Charging Demonstration at ACM	1,300	1,292	(8)	
29	Interconnection Process Enablement	3,991	3,693	(298)	
30	Grid Edge Insights & New Technology	1,960	1,819	(141)	
31	DER Control	290	-	(290)	
32	ADMS Enhancements	-	-	-	
33	Operational Technology and Error Free Communication	-	136	136	
34	Meter Improvements	-	-	-	
35	FLISR Implementation	-	-	-	
36	DERMS	4,640	-	(4,640)	Postponed investment while awaiting finalized MISO FERC 2222 requirements
37	Substation Cybersecurity	1,700	1,339	(361)	
38	Automation Configuration and Test Record Database	2,250	-	(2,250)	Project start delayed
39	Microwave End of Life	500	-	(500)	
40	Other Modernize Grid Management	375	26,411	26,036	See Witness Hartwick's testimony
41	ADMS: Network Management System	2,900	1,998	(902)	
42	Load Forecasting & Analytics	5,506	2,841	(2,665)	Project start delayed
43	Hosting Capacity Enablement	250	253	3	
44	Power Quality Analysis Program	-	-	-	
45	Substation Design Tool Upgrades	2,653	597	(2,056)	Project start delayed
46	Distribution Planning	-	8,447	8,447	Investments to bring operational data into the ADMS system
47	Enhance Maximo Capabilities and Processes	-	-	-	
48	Primary Service Orders Replatform	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 9 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
49	Work Management & Scheduling Upgrades	7,350	6,516	(834)	
50	Mobile tools expansion	-	-	-	
51	Maintain compliance	-	-	-	
52	Enhance and expand cybersecurity	-	-	-	
53	Mobile Equipment Replacement	-	-	-	
54	Mobile Technology	4,575	5,095	520	
55	SCADA / AMI Enhancements	-	-	-	
56	Total Technology and Automation Projects and Programs	136,604	165,605	29,001	

1/ Variance greater than two million dollars are explained
2/ Distribution Automation is collectively "Automation: Substation", "Automation: 13.2kV Circuit Distributions", and "4.8 kV Circuit Automation" in U-21297 (See Exh A-12, Sch B5.4, pg. 12 Line 9, 10, and 39, respectively)

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 1 of 8

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast	Over / (Under) Percentage
1	Base Capital Programs				
2	Emergent Replacements				
3	Storm	226,973	244,066	17,093	8%
4	Non - Storm	188,384	220,275	31,892	17%
5	Substation Reactive	47,302	49,057	1,754	4%
6	Emergent Replacement Reduction Based on Strategic Spend	(39,239)	(20,820)	18,419	-47%
7	Subtotal Emergent Replacements	423,420	492,578	69,158	16%
8	Customer Connections, Relocations & Other				
9	Connections and New Load	203,345	206,069	2,724	1%
10	Relocations	26,521	52,202	25,681	97%
11	Electric System Equipment	30,138	33,300	3,162	10%
12	NRUC and Improvement Blankets	23,051	29,611	6,561	28%
13	General Plant, Tools & Equipment and Miscellaneous	6,262	9,144	2,882	46%
14	Public Lighting Department Project	-	-	-	
15	Subtotal Customer Connections, Relocations & Other	289,317	330,327	41,010	14%
13	Customer Advances for Construction	(27,940)	(27,111)	829	-3%
14	Total Base Capital Programs	684,797	795,794	110,998	16%
15					
16	Strategic Capital Programs				
17	Infrastructure Resilience and Hardening	238,796	295,363	56,566	24%
18	Infrastructure Redesign and Modernization	543,244	291,496	(251,749)	-46%
19	Technology and Automation	97,538	121,919	24,381	25%
20	Subtotal Strategic Capital Programs	879,579	708,777	(170,802)	-19%
21					
22	Total Capital	1,564,376	1,504,572	(59,804)	-4%

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 2 of 8

	(a)	(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	<u>Connections and New Load</u>			
2	Projected Small Load Growth Projects (Blanket)	23,831	21,962	(1,869)
3				
4	Projected Customer Connections	119,708	121,101	1,393
5	Projected Customer Connections CIAC	(17,079)	(18,091)	(1,011)
6	Projected Customer Connections (Net of CIAC)	102,629	103,011	382
7				
8	Projected New Business Projects	59,806	58,305	(1,501)
9	Projected New Business Projects CIAC	(10,330)	(7,298)	3,032
10	Projected New Business Projects (net of CIAC)	49,475	51,007	1,532
11				
12	Incremental Infrastructure for EV	-	4,700	4,700
13				
14	Total Connections and New Load	203,345	206,069	2,724
15	Total Connections and New Load CIAC	(27,410)	(25,388)	2,021
16	Total Connections and New Load (Net of CIAC)	175,935	180,680	4,745
17				
18	<u>Relocations</u>			
19	Projected Small Relocation Projects (Blanket)	7,721	11,651	3,930
20				
21	Major Infrastructure Relocation Project			
22	Gordie Howe International Bridge	-	-	-
23	I-375 Relocations	-	25,000	25,000
24				
25	Relocation Projects (excl. Major Infrastructure Projects)	18,800	15,551	(3,249)
26	Relocation Projects CIAC	(531)	(1,723)	(1,192)
27	Subtotal Relocation Projects (Net of CIAC)	18,269	13,828	(4,441)
28				
29	Total Relocations	26,521	52,202	25,681
30	Total Relocations CIAC	(531)	(1,723)	(1,192)
31	Total Relocations (Net of CIAC)	25,990	50,480	24,490
32				
33	<u>Electric System Equipment</u>			
34	Distribution Transformers & Regulators	-	-	-
35	Projected Major Equipment	14,956	15,742	786
36	Projected Meters	15,183	17,559	2,376
37	Total Electric System Equipment	30,138	33,300	3,162
38				
39	<u>NRUC and Improvement Blankets</u>			
40	Projected System Improvements	10,688	16,454	5,766
41	Projected Normal Retirement Unit Changeouts (NRUC)	6,273	6,904	631
42	Projected Operational Technologies	6,089	6,253	164
43	Total NRUC and Improvement Blankets	23,051	29,611	6,561
44				
45	<u>General Plant, Tools & Equipment and Miscellaneous</u>			
46	Projected Substation Physical Security	-	1,127	1,127
47	Projected General Plant, Tools & Equipment and Miscellaneous	6,262	8,017	1,755
48	Total General Plant, Tools & Equipment and Miscellaneous	6,262	9,144	2,882
49				
50	<u>Public Lighting Department Project</u>			
51		-	-	-
52	Total Customer Connections, Relocations & Other	289,317	330,327	41,010
53	Total Cust Connections, Relocations & Other CIAC	(27,940)	(27,111)	829
54	Total Cust Connections, Relocations & Other Net of CIAC	261,376	303,216	41,840

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Resilience and Hardening
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 3 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	Infrastructure Resilience and Hardening			
2	Mobile Fleet Program	4,500	5,000	500
3	Substation Risk: Drexel	-	-	-
4	Substation Risk: Chestnut	7,245	2,725	(4,520)
5	Substation Risk: Savage	-	-	-
6	Substation Risk: Apache	2,638	3,810	1,173
7	Substation Risk: Port Huron	-	-	-
8	Substation Risk: Belleville Switchgear Decommission	-	-	-
9	Substation Risk: McGraw	9	37,852	37,843
10	Substation Risk: Voyager	-	-	-
11	Substation Risk: Flood Defense Program	-	5,009	5,009
12	4.8 kV Hardening	-	80,000	80,000
13	Pole and Pole Top Maintenance and Modernization (PTMM)	120,587	63,450	(57,137)
14	Cable Replacement Program	25,000	15,001	(9,999)
15	Frequent Outage Program (CEMI)	47,625	48,050	425
16	Breaker Replacement Program	-	-	-
17	Pontiac Vaults	-	-	-
18	URD Replacement Program	-	-	-
19	URD Replacement Program: Detroit URD 1-1	-	-	-
20	40 kV: Automatic Pole Top Switch	6,338	4,995	(1,343)
21	Disconnect and Switcher Replacement	4,900	4,900	-
22	Steel Pole Highway Crossings	5,000	5,000	-
23	Station Upgrade: Warren (Relay Replacement)	-	-	-
24	Station Upgrade: Northeast (Relay Replacement)	-	-	-
25	Batteries and Chargers Replacement Program	2,500	2,500	-
26	Substation Risk: Hood	-	6,918	6,918
27	Substation Risk: UNVIL 301 B1 Conversion	-	-	-
28	Portable Generators	-	4,500	4,500
29	Station Upgrade: Lincoln	5,300	-	(5,300)
30	SCADA Pole Top Device Replacement	1,808	1,808	-
31	Substation Regulator Replacement	904	816	(88)
32	Station Upgrade: Navarre	330	330	-
33	Station Upgrade: 120kV Relays Upgrade for ITC Projects	4,112	2,698	(1,414)
34	Substation Risk: Savage Switchgear Replacement	-	-	-
35	Substation Risk: Seville	-	-	-
36	Substation Risk: Imlay	-	-	-
37	Total Infrastructure Resilience and Hardening Projects and Programs	238,796	295,363	56,566

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 4 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	Infrastructure Redesign and Modernization			
2	Ann Arbor System Improvements: State Substation	-	-	-
3	Ann Arbor System Improvements: Apex (Blue) Substation	-	-	-
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	7,400	3,000	(4,400)
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	5,500	4,745	(755)
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	-	-	-
7	Subtransmission Redesign & Rebuild: Trunk 7106	-	-	-
8	Subtransmission Redesign & Rebuild: Trunk 2255	-	-	-
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	-	-	-
10	Subtransmission Redesign & Rebuild: Trunk 7333	-	-	-
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	4,070	4,070
12	Subtransmission Redesign & Rebuild: Boyne	-	3,026	3,026
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1 1/	-	-	-
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3 1/	1,817	2,259	442
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4 1/	8,490	-	(8,490)
16	Subtransmission Redesign & Rebuild: Tie 1568	-	-	-
17	Subtransmission Redesign & Rebuild: Trunk 4217	-	2,265	2,265
18	Subtransmission Redesign & Rebuild: Trunk 3509	1,217	3,653	2,437
19	Subtransmission Redesign & Rebuild: Trunk 4266	5,096	-	(5,096)
20	Subtransmission Redesign & Rebuild: Praxair	-	565	565
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	415	500	85
22	Subtransmission Breaker Short Circuit Violations	95	50	(45)
23	Subtransmission Redesign & Rebuild: Slocum	-	-	-
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	-	260	260
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-
26	Subtransmission Redesign & Rebuild: Tie 6907	1,790	-	(1,790)
27	Subtransmission Redesign & Rebuild: Tie 6602	3,689	-	(3,689)
28	Subtransmission Redesign & Rebuild: Trunk 2419	785	-	(785)
29	Subtransmission Redesign & Rebuild: Kennett	315	-	(315)
30	Subtransmission Redesign & Rebuild: Trunk 4601	1,711	-	(1,711)
31	Subtransmission Redesign & Rebuild: Tempest Phase II	8,353	-	(8,353)
32	Subtransmission Redesign & Rebuild: Waterman	2,207	-	(2,207)
33	Subtransmission Redesign & Rebuild: Trunk 7105	270	-	(270)
34	Subtransmission Redesign & Rebuild: Tie 5208	500	-	(500)
35	TCHPP Switchyard Upgrades	-	3,309	3,309
36	Trunk and Tie Lines Hardening Program: Prior Year's	-	-	-
37	CODI: Charlotte Network Upgrade	11,673	10,967	(707)
38	CODI: Targeted Network Secondary Cable Replacement	3,800	3,800	-
39	CODI: Corktown Substation	-	-	-
40	CODI: Islandview Substation - Phase 1 2/	26	7	(20)
41	CODI: Islandview Substation - Phase 2 2/	30,932	8,000	(22,932)
42	CODI: Islandview Substation - Phase 3 2/	11,599	-	(11,599)
43	CODI: Islandview Substation - Phase 4 2/	3,866	-	(3,866)
44	CODI: Midtown Substation Expansion	-	459	459
45	CODI: Alfred Substation Expansion	11,782	18,235	6,452
46	CODI: Howard Conversion	15,000	-	(15,000)
47	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	-	2,537	2,537
48	4.8 kV CC: Ariel Substation and Circuit Conversion	-	-	-
49	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade 3/	-	-	-
50	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade 3/	4,063	1,311	(2,752)
51	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit 3/	11,630	-	(11,630)
52	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Phase 4 3/	17,446	-	(17,446)
53	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	-	6,000	6,000

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 5 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
54	4.8 kV CC: Buckler Circuit Conversion	2,648	3,922	1,274
55	4.8 kV CC: McKinstry Sub Decommission	-	3,376	3,376
56	4.8 kV CC: Quincy Conversion	-	1,692	1,692
57	4.8 kV CC: Pinegrove Substation Relocation and Conversion	24,780	51,226	26,446
58	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	(8,700)	(17,000)	(8,300)
59	4.8 kV CC: Hawthorne Relief and Circuit Conversion	13,000	3,373	(9,627)
60	4.8 kV CC: Crestwood Substation	-	-	-
61	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	-	-	-
62	4.8 kV CC: Power line Conversion of MADSN 175L-W	-	-	-
63	4.8 kV CC: GRFIN & WMSTN Conversions	8,019	6,300	(1,719)
64	4.8kV CC: SCOTN	1,087	1,885	798
65	4.8 kV CC: Slater	-	-	-
66	4.8 kV CC: Royal Oak Substation and Circuit Conversion	15,100	-	(15,100)
67	4.8 kV CC: Curtis	-	2,174	2,174
68	4.8 kV CC: Unionville DC 301 B1 Conversion	-	2,911	2,911
69	4.8 kV CC: Hilton Substation and Circuit Conversion	-	-	-
70	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	-	-	-
71	4.8kV CC: Rochester Decommissioning and Tienken Relief	711	-	(711)
72	4.8 kV CC: Ann Arbor AC Network Conversion	711	-	(711)
73	4.8kV CC: Pittsfield Substation and Circuit Conversion	2,423	-	(2,423)
74	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	4,319	-	(4,319)
75	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	15,100	-	(15,100)
76	System Loading: Brest Substation	-	-	-
77	System Loading: Carleton	-	-	-
78	System Loading: Grayling	-	-	-
79	System Loading: Prospect	-	-	-
80	System Loading: Mandy 307 Load Transfer	-	-	-
81	System Loading: Mack Transformer 102	-	-	-
82	System Loading: Globe	2,358	200	(2,158)
83	Pilot: Strategic and Service Undergrounding	1,900	15,644	13,744
84	Pilot: Primary Deconductoring	-	-	-
85	Subtransmission Redesign & Rebuild: Tie 810	20,890	13,000	(7,890)
86	Subtransmission Redesign & Rebuild: Tie 7504	6,430	500	(5,930)
87	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	1/ 161	-	(161)
88	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	1/ 161	-	(161)
89	Subtransmission Redesign & Rebuild: Trunk 2308	2,030	970	(1,060)
90	Subtransmission Redesign & Rebuild: Tie 3205	4,793	-	(4,793)
91	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	150	150
92	Subtransmission Redesign & Rebuild: Tie 4104	11,697	-	(11,697)
93	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	1,503	580	(923)
94	Subtransmission Redesign & Rebuild: Trunk 4245	1,000	600	(400)
95	Subtransmission Redesign & Rebuild: Trunk 4911	8,209	-	(8,209)
96	Subtransmission Redesign & Rebuild: Custer Republic	1,658	-	(1,658)
97	Subtransmission Redesign & Rebuild: Cortland Station Expansion	2,379	101	(2,278)
98	CODI: CATO Substation Expansion	13,300	14,172	872
99	CODI: Garfield Radial (Midtown Circuits)	4/ 17,151	11,633	(5,518)
100	CODI: Garfield Network Upgrade	4/ 19,068	17,300	(1,768)
101	CODI: Kent/Gibson Conversion - Phase 1	5/ 39,751	15,107	(24,644)
102	4.8 kV CC: Zenon Substation and Circuit Conversion	-	-	-
103	4.8 kV CC: Calla Circuit Conversion and Phase 2	3,926	-	(3,926)
104	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	16,982	3,558	(13,424)
105	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	4,540	1,333	(3,207)
106	4.8 kV CC: ISO Conversion Program	40,000	1,700	(38,300)

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 6 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
107	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	1,371	750	(621)
108	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	-	-	-
109	8.3 kV CC: Pontiac Overhead Conversion	23,582	19,177	(4,405)
110	8.3 kV CC: Pontiac Underground Conversion	3,428	3,250	(178)
111	System Loading: Brown City	8,392	7,392	(1,000)
112	System Loading: Port Sanilac	6,034	2,389	(3,645)
113	System Loading: Richmond/Armada	7,050	8,893	1,843
114	System Loading: Cody	1,584	1,600	16
115	System Loading: Otsego/Capac/Shaw	1,688	88	(1,600)
116	System Loading: Macomb/Golf	126	-	(126)
117	System Loading: Grenada	7,535	6,535	(1,000)
118	System Loading: Lark/Spruce	607	1,350	744
119	System Loading: Jewell	500	592	92
120	System Loading: Mayville	150	-	(150)
121	System Loading: Goodison	79	-	(79)
122	System Loading: Wixom	3,033	2,033	(1,000)
123	System Loading: Diamond	21	21	-
124	System Loading: Spokane/Seneca	5,984	-	(5,984)
125	System Loading: Sterling	756	336	(420)
126	System Loading: Disco	417	417	-
127	System Loading: Tahoe	354	-	(354)
128	System Loading: New Baltimore/Chesterfield	-	250	250
129	System Loading: Kings Point	-	1,000	1,000
130	Total Infrastructure Redesign and Modernization Projects and Programs	543,244	291,496	(251,749)

1/ Tie 4105 phases on lines 13-15 and 84-85 were collectively "Subtransmission Redesign & Rebuild: Tie 4105" in U-21297 (Exh A-12, Sch B5.4, pg. 9, Line 17). Tie 4105 was forecasted at \$10,629 in U-21297 compared to \$2,259 in U-21534.

2/ CODI: Islandview Substation phases on lines 40-43 were collectively "CODI: Islandview Substation" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 45). Islandview was forecasted at \$46,424 in U-21297 compared to \$8,007 in U-21534.

3/ Promenade phases on lines 49-50 and 127-128 were collectively "4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 56). Promenade was forecasted at \$33,139 in U-21297 compared to \$1,311 in U-21534.

4/ CODI: Garfield projects on lines 99-100 were collectively "CODI: Garfield Network Upgrade" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 50). CODI: Garfield was forecasted \$36,220 in U-21297 compared to \$28,933 in U-21534.

5/ CODI: Kent/Gibson Conversion - Phase 1 on line 82 was "CODI: Kent/Gibson Conversion" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 51).

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 7 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	<u>Technology and Automation</u>			
2	Distribution Automation	1/ 29,000	21,188	(7,812)
3	ADMS: DMS/OMS	-	-	-
4	SOC: ESOC	-	-	-
5	SOC: ASOC	1,000	-	(1,000)
6	Grid Automation Telecommunications	16,861	16,900	39
7	Distribution Sensing and Monitoring (inclgd Line Sensors)	-	500	500
8	CVR/VVO	5,000	2,500	(2,500)
9	NWA: O'Shea Energy Storage	-	54	54
10	NWA: Battery Trailer	2,250	2,250	-
11	NWA: Omega Load Relief	-	27	27
12	NWA: Fisher Load Relief	4,650	4,524	(126)
13	NWA: Port Austin Load Relief	775	1,486	710
14	NWA: Small Solar and Storage Testbed	500	565	65
15	Sensor, Network and Algorithm Development (Solar Deployment)	204	200	(4)
16	Technology Programs & NWA	-	-	-
17	AMI: Meter Communications Upgrades	-	-	-
18	Customer Power Status Visibility	-	15,942	15,942
19	SCADA Remote Access and Configuration Platform	-	-	-
20	Substation Reporting and Process Enhancements	-	200	200
21	Asset Management Upgrades	1,500	-	(1,500)
22	Systematic Tracking of Rotatable Assets	-	-	-
23	External Crew Efficiency	-	4,407	4,407
24	Tree Trim Risk Prioritization Model	-	-	-
25	NWA: Veridian	4,625	2,646	(1,979)
26	NWA: Adaptive Networked Microgrids	-	4,588	4,588
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	(2,609)	(2,609)
28	NWA: EV Charging Demonstration at ACM	2,628	920	(1,709)
29	Interconnection Process Enablement	5,607	1,900	(3,707)
30	Grid Edge Insights & New Technology	2,191	5,935	3,744
31	DER Control	290	290	-
32	ADMS Enhancements	-	7,000	7,000
33	Operational Technology and Error Free Communication	-	5,600	5,600
34	Meter Improvements	-	1,400	1,400
35	FLISR Implementation	-	4,412	4,412
36	DERMS	2,540	-	(2,540)
37	Substation Cybersecurity	-	400	400
38	Automation Configuration and Test Record Database	2,250	1,400	(850)
39	Microwave End of Life	500	250	(250)
40	Other Modernize Grid Management	2,225	2,200	(25)
41	ADMS: Network Management System	2,900	1,600	(1,300)
42	Load Forecasting & Analytics	4,275	3,900	(375)
43	Hosting Capacity Enablement	150	350	200
44	Power Quality Analysis Program	-	400	400
45	Substation Design Tool Upgrades	1,866	1,250	(616)
46	Distribution Planning	-	1,572	1,572
47	Enhance Maximo Capabilities and Processes	-	-	-
48	Primary Service Orders Replatform	-	2,000	2,000
49	Work Management & Scheduling Upgrades	3,025	790	(2,235)
50	Mobile tools expansion	-	1,100	1,100
51	Maintain compliance	-	200	200
52	Enhance and expand cybersecurity	-	300	300
53	Mobile Equipment Replacement	-	881	881

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 8 of 8

	(a)	(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
54	Mobile Technology	725	500	(225)
55	SCADA / AMI Enhancements	-	-	-
56	Total Technology and Automation Projects and Programs	97,538	121,919	24,381

1/ Distribution Automation is collectively "Automation: Substation", "Automation: 13.2kV Circuit Distributions", and "4.8 kV Circuit Automation" in U-21297 (See Exh A-12, Sch B5.4, pg. 12 Line 9, 10, and 39, respectively)

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 1 of 11

(a) (b)

Category	Distribution Plant Capital Project Detail - Base Capital
	Capital Exhibit:
page: 2 of 11	Exhibit A-12, Schedule B5.4, Page 3 of 26, Lines 2-28 Emergent Replacements
page: 3 of 11	Exhibit A-12, Schedule B5.4, Page 5 of 26, Lines 2-16, Small Load Growth Blankets & Customer Connections
page: 4 of 11	Exhibit A-12, Schedule B5.4, Page 5 of 26, Lines 17-28, New Business Projects
page: 5 of 11	Exhibit A-12, Schedule B5.4, Page 7 of 26, Lines 33-52, Relocations
page: 6 of 11	Exhibit A-12, Schedule B5.4, Page 7 of 26, Lines 53-63, Electric System Equipment
page: 7 of 11	Exhibit A-12, Schedule B5.4, Page 9 of 26, Lines 64-77, NRUC and Improvement Blankets
page: 8 of 11	Exhibit A-12, Schedule B5.4, Page 9 of 26, Line 78-87, General Plant, Tools & Equipment
page: 9 of 11	Exhibit A-12, Schedule B5.4, Page 9 of 26, Line 88, Public Lighting of Detroit
page: 10 of 11	Exhibit A-12, Schedule B5.4, page 10 & 11 of 26, Lines 2-84, Prior Year's New Business Projects
page: 11 of 11	Exhibit A-12, Schedule B5.4, Page 12 of 26, Lines 2-29, Prior Year's Relocation Projects

(a)	(b)																																				
Program:	Emergent Replacements																																				
Purpose and Necessity:	Investment required to perform emergency replacement work on the overhead and underground distribution and subtransmission systems, and substation equipment. Drivers of this work include, but are not limited to, damage from storms, wind, trees, ice, and equipment failures.																																				
Category:	Emergent Replacements																																				
Line Number:	Exhibit A-12, Schedule B5.4, Page 3, Lines 2-28																																				
DGP Section:	15.1-15.3																																				
Scope:	• Reactive replacement of broken or damaged equipment																																				
Customer benefit / Effect on cost of operation and reliability:	• Restore power to customers during outage events • Remove hazards from the field after outage events and restore the electrical system to normal operating conditions																																				
Current Projects:	• Work performed to address storm events • Work performed to address non-storm events • Work performed to address emergent substation events																																				
Cost:	Estimated program investment in 2023-2025: \$1,531 million The program will continue beyond the Test Year																																				
Test Year (\$000's):	<table><tr><td></td><td>12 mos.</td><td>12 mos.</td><td>12 mos.</td></tr><tr><td></td><td>1/1/23</td><td>1/1/24</td><td>1/1/25</td></tr><tr><td></td><td>12/31/23</td><td>12/31/24</td><td>12/31/25</td></tr><tr><td>Total Labor (DTE Electric & Contractors)</td><td>398,443</td><td>385,049</td><td>396,215</td></tr><tr><td>Material</td><td>106,251</td><td>102,680</td><td>105,657</td></tr><tr><td>Other</td><td>26,563</td><td>25,670</td><td>26,414</td></tr><tr><td>Subtotal</td><td>531,257</td><td>513,398</td><td>528,287</td></tr><tr><td>Reduction based on Strategic investment</td><td>-</td><td>(20,820)</td><td>(21,436)</td></tr><tr><td>Total</td><td>531,257</td><td>492,578</td><td>506,851</td></tr></table>		12 mos.	12 mos.	12 mos.		1/1/23	1/1/24	1/1/25		12/31/23	12/31/24	12/31/25	Total Labor (DTE Electric & Contractors)	398,443	385,049	396,215	Material	106,251	102,680	105,657	Other	26,563	25,670	26,414	Subtotal	531,257	513,398	528,287	Reduction based on Strategic investment	-	(20,820)	(21,436)	Total	531,257	492,578	506,851
	12 mos.	12 mos.	12 mos.																																		
	1/1/23	1/1/24	1/1/25																																		
	12/31/23	12/31/24	12/31/25																																		
Total Labor (DTE Electric & Contractors)	398,443	385,049	396,215																																		
Material	106,251	102,680	105,657																																		
Other	26,563	25,670	26,414																																		
Subtotal	531,257	513,398	528,287																																		
Reduction based on Strategic investment	-	(20,820)	(21,436)																																		
Total	531,257	492,578	506,851																																		

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 3 of 11

(a)

(b)

Program:	Small Load Growth Projects & Customer Connections			
Purpose and Necessity:	Small projects (<\$350k) required to serve new load, customer connections, or to address loading issues on the electric system.			
Category:	Connections, Relocations & Other			
Line Number:	Exhibit A-12, Schedule B5.4, Page 5, Lines 2-16, 29			
DGP Section:	15.2.1			
Scope:	• Reconductor lines and/or transfer load to provide small load relief • Install additional overhead and underground lines to provide electric services to small commercial business or housing developments • Electric vehicle infrastructure			
Customer benefit / Effect on cost of operation and reliability:	• Connect new customers • Support area load growth for existing and new customers • Enable economic growth in the service territory • Improve customer satisfaction			
Current Projects:	• Small load growth • Line extensions • New services			
Cost:	Estimated program investment in 2023-2025: \$394 million (net of CIAC) The program will continue beyond the Test Year			
Test Year (\$000's):		12 mos. 1/1/23 12/31/23	12 mos. 1/1/24 12/31/24	12 mos. 1/1/25 12/31/25
	Total Labor (DTE Electric & Contractors)	105,999	110,823	118,959
	Material	21,200	22,165	23,792
	Other	14,133	14,776	15,861
	Subtotal	141,332	147,763	158,612
	CIAC	(16,782)	(18,091)	(18,615)
	Total	124,550	129,673	139,997

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 4 of 11

(a)	(b)																												
Program:	New Business Projects																												
Purpose and Necessity:	Large projects (\$>350k) required to serve new load.																												
Category:	Connections, Relocations & Other																												
Line Number:	Exhibit A-12, Schedule B5.4, Page 5, Lines 17-28																												
DGP Section:	15.2.1																												
Scope:	• Install additional overhead and underground lines, upgrade or build new substations to provide service to large commercial and industrial customers																												
Customer benefit / Effect on cost of operation and reliability:	• Connect new customers • Support area load growth for existing and new customers • Enable economic growth in the service territory • Improve customer satisfaction																												
Current Projects:	• New business fed from MOTT substation • New business fed from Pontiac-Sunbird 120kV line • New business fed from FRGOV substation • New business for new industrial sub and line extension • New business fed from DERBY station/TIE 9111 • New business fed from TAMRK substation • New business fed from ARGO substation • New business fed from GLBRT substation • New business fed from MARTN substation • New business fed from OTTWA substation • New business fed from JSLYN substation • New business fed from MORTON substation • New business fed from ORION substation • New business fed from Lenox-Stephens 120kV line • New business fed from NRLND substation																												
Cost:	Estimated program investment in 2023-2025: \$173 million (net of CIAC) The program will continue beyond the Test Year																												
Test Year (\$000's):	<table><tr><td></td><td>12 mos. 1/1/23 12/31/23</td><td>12 mos. 1/1/24 12/31/24</td><td>12 mos. 1/1/25 12/31/25</td></tr><tr><td>Total Labor (DTE Electric & Contractors)</td><td>56,704</td><td>43,729</td><td>44,997</td></tr><tr><td>Material</td><td>11,341</td><td>8,746</td><td>8,999</td></tr><tr><td>Other</td><td>7,561</td><td>5,831</td><td>6,000</td></tr><tr><td>Subtotal</td><td>75,606</td><td>58,305</td><td>59,996</td></tr><tr><td>CIAC</td><td>(5,847)</td><td>(7,298)</td><td>(7,510)</td></tr><tr><td>Total</td><td>69,759</td><td>51,007</td><td>52,486</td></tr></table>		12 mos. 1/1/23 12/31/23	12 mos. 1/1/24 12/31/24	12 mos. 1/1/25 12/31/25	Total Labor (DTE Electric & Contractors)	56,704	43,729	44,997	Material	11,341	8,746	8,999	Other	7,561	5,831	6,000	Subtotal	75,606	58,305	59,996	CIAC	(5,847)	(7,298)	(7,510)	Total	69,759	51,007	52,486
	12 mos. 1/1/23 12/31/23	12 mos. 1/1/24 12/31/24	12 mos. 1/1/25 12/31/25																										
Total Labor (DTE Electric & Contractors)	56,704	43,729	44,997																										
Material	11,341	8,746	8,999																										
Other	7,561	5,831	6,000																										
Subtotal	75,606	58,305	59,996																										
CIAC	(5,847)	(7,298)	(7,510)																										
Total	69,759	51,007	52,486																										

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 5 of 11

(a)	(b)																																				
Program:	Relocations																																				
Purpose and Necessity:	Requests from customers and municipalities to relocate existing facilities.																																				
Category:	Connections, Relocations & Other																																				
Line Number:	Exhibit A-12, Schedule B5.4, Page 7, Lines 33-52																																				
DGP Section:	15.2.2																																				
Scope:	• Relocation of DTE Electric facilities due to construction or modification of roadways, water mains, public sanitation, alleys, or at the request of municipalities or customers																																				
Customer benefit / Effect on cost of operation and reliability:	• Enable economic growth in the service territory • Meet customer requests as required by regulation																																				
Current Projects:	• Small Relocation Projects • Grand River I-96 Bridge Relocation • I-375 Relocations • Cass I-94 Bridge Relocation • Mound Road Relocation																																				
Cost:	Estimated program investment in 2023-2025: \$130 million (net of CIAC) The program will continue beyond the Test Year																																				
Test Year (\$000's):	<table><tr><td></td><td>12 mos.</td><td>12 mos.</td><td>12 mos.</td></tr><tr><td></td><td>1/1/23</td><td>1/1/24</td><td>1/1/25</td></tr><tr><td></td><td>12/31/23</td><td>12/31/24</td><td>12/31/25</td></tr><tr><td>Total Labor (DTE Electric & Contractors)</td><td>34,331</td><td>39,152</td><td>26,993</td></tr><tr><td>Material</td><td>6,866</td><td>7,830</td><td>5,399</td></tr><tr><td>Other</td><td>4,577</td><td>5,220</td><td>3,599</td></tr><tr><td>Subtotal</td><td>45,774</td><td>52,202</td><td>35,991</td></tr><tr><td>CIAC</td><td>(157)</td><td>(1,723)</td><td>(1,773)</td></tr><tr><td>Total</td><td>45,618</td><td>50,480</td><td>34,219</td></tr></table>		12 mos.	12 mos.	12 mos.		1/1/23	1/1/24	1/1/25		12/31/23	12/31/24	12/31/25	Total Labor (DTE Electric & Contractors)	34,331	39,152	26,993	Material	6,866	7,830	5,399	Other	4,577	5,220	3,599	Subtotal	45,774	52,202	35,991	CIAC	(157)	(1,723)	(1,773)	Total	45,618	50,480	34,219
	12 mos.	12 mos.	12 mos.																																		
	1/1/23	1/1/24	1/1/25																																		
	12/31/23	12/31/24	12/31/25																																		
Total Labor (DTE Electric & Contractors)	34,331	39,152	26,993																																		
Material	6,866	7,830	5,399																																		
Other	4,577	5,220	3,599																																		
Subtotal	45,774	52,202	35,991																																		
CIAC	(157)	(1,723)	(1,773)																																		
Total	45,618	50,480	34,219																																		

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 6 of 11

(a)	(b)																												
Program:	Electric System Equipment																												
Purpose and Necessity:	Investment required for large transformers and other equipment needed for emergent replacements, customer connections and relocations and to maintain proper inventory level for major electric system equipment, particularly for long lead time items.																												
Category:	Connections, Relocations & Other																												
Line Number:	Exhibit A-12, Schedule B5.4, Page 7, Lines 53-63																												
DGP Section:	15.2.3																												
Scope:	• Purchase major equipment, such as substation transformers • Purchase and install meters																												
Customer benefit / Effect on cost of operation and reliability:	• Ensure equipment is readily available to serve customers																												
Current Projects:	Equipment types: • Major equipment • Meters																												
Cost:	Estimated program investment in 2023-2025: \$101 million The program will continue beyond the Test Year																												
Test Year (\$000's):	<table><tr><td></td><td>12 mos.</td><td>12 mos.</td><td>12 mos.</td></tr><tr><td></td><td>1/1/23</td><td>1/1/24</td><td>1/1/25</td></tr><tr><td></td><td>12/31/23</td><td>12/31/24</td><td>12/31/25</td></tr><tr><td>Total Labor (DTE Electric & Contractors)</td><td>8,414</td><td>8,325</td><td>8,567</td></tr><tr><td>Material</td><td>22,549</td><td>22,311</td><td>22,958</td></tr><tr><td>Other</td><td>2,692</td><td>2,664</td><td>2,741</td></tr><tr><td>Total</td><td>33,655</td><td>33,300</td><td>34,266</td></tr></table>		12 mos.	12 mos.	12 mos.		1/1/23	1/1/24	1/1/25		12/31/23	12/31/24	12/31/25	Total Labor (DTE Electric & Contractors)	8,414	8,325	8,567	Material	22,549	22,311	22,958	Other	2,692	2,664	2,741	Total	33,655	33,300	34,266
	12 mos.	12 mos.	12 mos.																										
	1/1/23	1/1/24	1/1/25																										
	12/31/23	12/31/24	12/31/25																										
Total Labor (DTE Electric & Contractors)	8,414	8,325	8,567																										
Material	22,549	22,311	22,958																										
Other	2,692	2,664	2,741																										
Total	33,655	33,300	34,266																										

(a)	(b)																												
Program:	NRUC and Improvement Blankets																												
Purpose and Necessity:	This category includes projects for planned replacements, improvements to the electrical system and software applications for field use.																												
Category:	Connections, Relocations & Other																												
Line Number:	Exhibit A-12, Schedule B5.4, Page 9, Lines 64-77																												
DGP Section:	15.2.4																												
Scope:	• System Improvements: projects that are focused on reducing the frequency and duration of customer outages. Unlike larger scale, longer time frame projects like conversions or subtransmission projects, they are smaller scope projects managed by regional operations to immediately address localized customer issues and complaints. These projects do not exceed \$350,000 and do not require extended planning and design. • Normal Retirement Unit Changeout (NRUC): projects to perform scheduled work for normal retirement unit change out items on the subtransmission and distribution systems, for example the replacement of reclosers and switches determined to be at end-of-life during routine preventive maintenance inspections. • Operational Technology: infrastructure and associated applications that support the AMI platform and data. This also covers annual work in testing new meter types, designing and installing configurations, replacing communications equipment, and testing changes for new equipment.																												
Customer benefit / Effect on cost of operation and reliability:	• Projects are focused on improving operating conditions to reduce the frequency and duration of outage events • Replacement of critical infrastructure to support subtransmission, distribution, and communication systems																												
Current Projects:	• System Improvements • Normal Retirement Unit Changeouts (NRUC) • Operational Technologies																												
Cost:	Estimated program investment in 2023-2025: \$79 million The program will continue beyond the Test Year																												
Test Year (\$000's):	<table><tr><td></td><td>12 mos.</td><td>12 mos.</td><td>12 mos.</td></tr><tr><td></td><td>1/1/23</td><td>1/1/24</td><td>1/1/25</td></tr><tr><td></td><td>12/31/23</td><td>12/31/24</td><td>12/31/25</td></tr><tr><td>Total Labor (DTE Electric & Contractors)</td><td>15,624</td><td>23,689</td><td>24,376</td></tr><tr><td>Material</td><td>1,953</td><td>2,961</td><td>3,047</td></tr><tr><td>Other</td><td>1,953</td><td>2,961</td><td>3,047</td></tr><tr><td>Total</td><td>19,531</td><td>29,611</td><td>30,470</td></tr></table>		12 mos.	12 mos.	12 mos.		1/1/23	1/1/24	1/1/25		12/31/23	12/31/24	12/31/25	Total Labor (DTE Electric & Contractors)	15,624	23,689	24,376	Material	1,953	2,961	3,047	Other	1,953	2,961	3,047	Total	19,531	29,611	30,470
	12 mos.	12 mos.	12 mos.																										
	1/1/23	1/1/24	1/1/25																										
	12/31/23	12/31/24	12/31/25																										
Total Labor (DTE Electric & Contractors)	15,624	23,689	24,376																										
Material	1,953	2,961	3,047																										
Other	1,953	2,961	3,047																										
Total	19,531	29,611	30,470																										

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 8 of 11

(a)	(b)																												
Program:	General Plant, Tools & Equipment and Miscellaneous																												
Purpose and Necessity:	Capital expenditures for tools and test equipment required by field resources to perform their work.																												
Category:	Connections, Relocations & Other																												
Line Number:	Exhibit A-12, Schedule B5.4, Page 9, Lines 78-87																												
DGP Section:	15.2.5																												
Scope:	• Purchase tools and test equipment																												
Customer benefit / Effect on cost of operation and reliability:	• Provide employees required tools and test equipment to support field work so that they can maintain and operate the electric grid.																												
Current Projects:	• New tools and equipment for linemen and splicer apprentices • Replacement tools for linemen, splicers, electric maintenance journeyman • Test equipment for engineers and technicians																												
Cost:	Estimated program investment in 2023-2025: \$24 million The program will continue beyond the Test Year																												
Test Year (\$000's):	<table><tr><td></td><td>12 mos.</td><td>12 mos.</td><td>12 mos.</td></tr><tr><td></td><td>1/1/23</td><td>1/1/24</td><td>1/1/25</td></tr><tr><td></td><td>12/31/23</td><td>12/31/24</td><td>12/31/25</td></tr><tr><td>Total Labor (DTE Electric & Contractors)</td><td>883</td><td>1,372</td><td>1,411</td></tr><tr><td>Material</td><td>4,415</td><td>6,858</td><td>7,057</td></tr><tr><td>Other</td><td>589</td><td>914</td><td>941</td></tr><tr><td>Total</td><td>5,886</td><td>9,144</td><td>9,410</td></tr></table>		12 mos.	12 mos.	12 mos.		1/1/23	1/1/24	1/1/25		12/31/23	12/31/24	12/31/25	Total Labor (DTE Electric & Contractors)	883	1,372	1,411	Material	4,415	6,858	7,057	Other	589	914	941	Total	5,886	9,144	9,410
	12 mos.	12 mos.	12 mos.																										
	1/1/23	1/1/24	1/1/25																										
	12/31/23	12/31/24	12/31/25																										
Total Labor (DTE Electric & Contractors)	883	1,372	1,411																										
Material	4,415	6,858	7,057																										
Other	589	914	941																										
Total	5,886	9,144	9,410																										

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 9 of 11

(a)	(b)		
Program:	Public Lighting Department Program		
Purpose and Necessity:	These capital investments support the transition of Public Lighting Department (PLD) customers to the Company's distribution system.		
Category:	Connections, Relocations & Other		
Line Number:	Exhibit A-12, Schedule B5.4, Page 9, Line 88		
DGP Section:	Program completed in 2023		
Scope:	• Extending the Company's overhead and underground distribution system to transition customers from the PLD system to the Company's distribution system		
Customer benefit / Effect on cost of operation and reliability:	• Improve safety and reliability in the area of the former PLD distribution system		
Current Projects:	Conversion of former PLD customers to the Company's distribution system was completed before the start of the projected test period.		
Cost:	Estimated program investment in 2023-2025: \$2 million The program will not continue beyond the Test Year		
Test Year (\$000's):	12 mos. 1/1/23 12/31/23	12 mos. 1/1/24 12/31/24	12 mos. 1/1/25 12/31/25

Michigan Public Service Commission
DTE Electric Company
Distribution Plant Capital Project Detail - Base Capital

Case No.: U-21534
Exhibit: A-23
Schedule: M4
Witness: B. L. Hill
Page: 10 of 11

(a)	(b)
Program:	Prior Year's New Business Projects
Purpose and Necessity:	Large projects (\$>350k) required to serve new load.
Category:	Connections, Relocations & Other
Line Number:	Exhibit A-12, Schedule B5.4, page 10-11, Lines 2-84
Scope:	• Capital projects to connect new customer load
Customer benefit / Effect on cost of operation and reliability:	• Connect new customers • Support area load growth for existing and new customers • Meet economic growth in the service territory • Improve customer satisfaction
Current Projects:	• Listed in Exhibit A-12, Schedule B5.4, page 10-11
Cost:	2022 investment \$72 million (net of CIAC)
Test Year (\$000's):	Not Applicable

(a) (b)

Program:	Prior Year's Relocation Projects
Purpose and Necessity:	Large projects (\$>350k) for requests from customers and municipalities to relocate existing facilities.
Category:	Connections, Relocations & Other
Line Number:	Exhibit A-12, Schedule B5.4, page 12, Lines 2-30
Scope:	Relocation of DTE Electric facilities due to construction or modification of roadways, water mains, public sanitation, alleys, or at the request of municipalities or customers
Customer benefit / Effect on cost of operation and reliability:	- Enable economic growth in the service territory - Meet customer requests as required by regulation
Current Projects:	Listed in Exhibit A-12, Schedule B5.4, page 12
Cost:	2022 investment \$14 million (net of CIAC)
Test Year (\$000's):	Not Applicable

Investment	Page	Capital Exhibit Reference
4.8 kV Hardening.....	3	Exhibit A-12, Schedule B5.4, Page 13, Line 12
40 kV: Automatic Pole Top Switch.....	7	Exhibit A-12, Schedule B5.4, Page 13, Line 20
Batteries and Chargers Replacement Program	11	Exhibit A-12, Schedule B5.4, Page 13, Line 25
Breaker Replacement Program	15	Exhibit A-12, Schedule B5.4, Page 13, Line 16
Cable Replacement Program.....	19	Exhibit A-12, Schedule B5.4, Page 13, Line 14
Disconnect and Switcher Replacement.....	23	Exhibit A-12, Schedule B5.4, Page 13, Line 21
Frequent Outage Program (CEMI).....	27	Exhibit A-12, Schedule B5.4, Page 13, Line 15
Mobile Fleet Program	31	Exhibit A-12, Schedule B5.4, Page 13, Line 2
Pole and Pole Top Maintenance and Modernization (PTMM).....	35	Exhibit A-12, Schedule B5.4, Page 13, Line 13
Pontiac Vaults.....	39	Exhibit A-12, Schedule B5.4, Page 13, Line 17
SCADA Pole Top Device Replacement	43	Exhibit A-12, Schedule B5.4, Page 13, Line 30
Station Upgrade: 120 kV Relays Upgrade for ITC Projects	47	Exhibit A-12, Schedule B5.4, Page 13, Line 33
Station Upgrade: Lincoln	51	Exhibit A-12, Schedule B5.4, Page 13, Line 29
Station Upgrade: Navarre.....	55	Exhibit A-12, Schedule B5.4, Page 13, Line 32
Station Upgrade: Northeast (Relay Replacement)	59	Exhibit A-12, Schedule B5.4, Page 13, Line 24
Station Upgrade: Warren (Relay Replacement)	63	Exhibit A-12, Schedule B5.4, Page 13, Line 23
Steel Pole Highway Crossings.....	67	Exhibit A-12, Schedule B5.4, Page 13, Line 22
Substation Regulator Replacement.....	71	Exhibit A-12, Schedule B5.4, Page 13, Line 31

Investment	Page	Capital Exhibit Reference
Substation Risk: Apache	75	Exhibit A-12, Schedule B5.4, Page 13, Line 6
Substation Risk: Belleville Switchgear Decommission	79	Exhibit A-12, Schedule B5.4, Page 13, Line 8
Substation Risk: Chestnut	83	Exhibit A-12, Schedule B5.4, Page 13, Line 4
Substation Risk: Drexel	87	Exhibit A-12, Schedule B5.4, Page 13, Line 3
Substation Risk: Flood Defense Program	91	Exhibit A-12, Schedule B5.4, Page 13, Line 11
Substation Risk: Hood	95	Exhibit A-12, Schedule B5.4, Page 13, Line 26
Substation Risk: Imlay	99	Exhibit A-12, Schedule B5.4, Page 13, Line 36
Substation Risk: McGraw	103	Exhibit A-12, Schedule B5.4, Page 13, Line 9
Substation Risk: Port Huron	108	Exhibit A-12, Schedule B5.4, Page 13, Line 7
Substation Risk: Savage	112	Exhibit A-12, Schedule B5.4, Page 13, Line 5
Substation Risk: Savage Switchgear Replacement	116	Exhibit A-12, Schedule B5.4, Page 13, Line 34
Substation Risk: Seville	120	Exhibit A-12, Schedule B5.4, Page 13, Line 35
Substation Risk: Voyager	124	Exhibit A-12, Schedule B5.4, Page 13, Line 10
URD Replacement Program	128	Exhibit A-12, Schedule B5.4, Page 13, Line 18

(a)

(b)

Program:	4.8 kV Hardening
Purpose and Necessity:	The 4.8 kV Hardening program was initially created as a safety program for our customers by removing the existing Detroit Public Lighting Department (DPLD) arc wire that is co-located with the DTE Electric’s distribution system within the City of Detroit. This arc wire is highly susceptible to wire downs and represents a public and employee safety hazard when it comes in contact with the DTE electrical grid. In addition, after further evaluation of the age and condition of our electrical grid in the city of Detroit, DTEE included additional scope to improve reliability and increase storm resiliency until the system is able to be converted to 13.2 kV.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 12

(a)

(b)

Program:	4.8 kV Hardening
Scope:	• Test all utility poles that have Company equipment attached and replace or reinforce those poles as needed • Trim trees as required to support construction activities • Replace wooden cross arms with fiberglass cross arms • Remove Detroit Public Lighting Department (DPLD) arc wire from Company-owned equipment and ensure the remaining Company wires are left in a safe configuration • Remove DPLD distribution wire from Company-owned equipment when it can be confirmed that the wire is not serving customers • Remove service lines to abandoned properties • Perform any additional necessary work as dictated by field conditions • Deconductoring - This work includes removing primary overhead construction and adding secondary overhead construction to serve sparsely populated areas. This work is aimed at improving reliability and reducing trouble events in some areas of the City of Detroit where inaccessible overhead construction in rear lots is encroached by fence lines and overgrown trees.

(a)

(b)

Program:	4.8 kV Hardening				
Benefits:	• Avoid 61 M customer minute interruptions annually by 2026 • Avoid \$4 M costs annually for both circuit tree-related and non-tree related reactive capital by 2026 • Extend the life of the 4.8 kV system, allowing the deferral of more expensive conversions to 13.2 kV				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV Hardening			
Approximate Construction Schedule:	Annual Program			
Budget Basis:	Spend based on engineering estimates to harden approximately 50% of the circuits in the City of Detroit, within 10 years			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$100,728,151	\$65,679,012	\$95,550,000
	Material	\$26,282,114	\$14,320,988	\$29,450,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$127,010,265	\$80,000,000	\$125,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	40 kV: Automatic Pole Top Switch
Purpose and Necessity:	Subtransmission pole top switch inspection procedures have been updated, resulting in the need to de-energize both sides of a 40 kV pole top switch in order to maintain the required minimal approach distance to energized 40 kV while performing a periodic inspection of the switch. This situation and the challenges of obtaining a shutdown on the 40 kV system has created a backlog of overdue pole top switch inspections. Many existing subtransmission pole top switches are not built to current design standards to allow both sides of the switch to be de-energized for routine maintenance and inspection without the need to deploy portable equipment to serve the substation load during these shutdowns. This results in delayed maintenance of the switches, limited shutdown windows, and increased O&M expenditures to perform the shutdown. The 40 kV pole top switches due for maintenance will be reviewed annually to identify if a bypass is a feasible option instead of using portable equipment to facilitate the shutdown for maintenance. Building and overhead line extension to bypass pole top switches allows for shutdowns without the need for portable substations or generators.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 20

(a)

(b)

Program:	40 kV: Automatic Pole Top Switch
Scope:	Build overhead line extensions to bypass pole top switches identified to allow for shutdowns without the need for a portable substation or generator(s). These overhead line extensions will be approximately 4 poles and 3 spans each of 40 kV (no underbuild).

(a)

(b)

Program:	40 kV: Automatic Pole Top Switch				
Benefits:	• O&M Savings per location every 8 years. • Adherence to preventative maintenance cycle for pole top switches with improvement in shutdown ability. • Benefits will be to aid in shutting down the equipment in order to inspect on cycle and if needed repair or replace it				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:				x	

(a)

(b)

Program:	40 kV: Automatic Pole Top Switch			
Approximate Construction Schedule:	Annual program			
Budget Basis:	Project Management Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$3,271,775	\$4,162,500	\$4,162,500
	Material	\$3,085,928	\$832,500	\$832,500
	Other	\$ 0	\$ 0	\$ 0
	Total	\$6,357,703	\$4,995,000	\$4,995,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Batteries and Chargers Replacement Program
Purpose and Necessity:	DC Systems (Batteries and Chargers) are used to provide reliable power to trip equipment during fault conditions. Failure of these systems would result in significantly longer duration faults, greater damage to equipment, larger outages, and increased hazards due to the inability to clear faults. In order to maintain proper operating conditions at substations, batteries and chargers must be replaced when they reach end-of-life.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 25

(a)

(b)

Program:	Batteries and Chargers Replacement Program
Scope:	• Replace substation batteries and chargers which are at end-of-life or have failed

(a)

(b)

Program:	Batteries and Chargers Replacement Program				
Benefits:	Maintain safety and system operability and reliability by: • Providing tripping potential to breakers and switchers • Providing control power to relays, remote terminal units (RTU), and telecommunications				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	X				

(a)

(b)

Program:	Batteries and Chargers Replacement Program			
Approximate Construction Schedule:	Annual Program - replace 75 units per year			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,560,745	\$1,705,700	\$2,062,742
	Material	\$781,836	\$794,300	\$967,155
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,342,581	\$2,500,000	\$3,029,897

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Breaker Replacement Program
Purpose and Necessity:	DTE Electric has approximately 6,000 circuit breakers. Out of the total population, 58% are candidates for replacement due to factors such as equipment condition, age, lack of available parts (no support from vendors), and environmental concerns (oil spills). A failure of a circuit breaker can cause outages on multiple circuits and could reduce system redundancy for an extended period of time during repairs. Approximately 60% of DTE Electric's circuit breakers are beyond industry life expectancy and should also be replaced over time. DTE works to extend asset life as much as possible through its preventative maintenance programs and uses equipment condition, not just age, to determine which breakers to replace and when. The industry life expectancy of a circuit breaker is approximately 40 years for early to mid-20th century equipment and 30 years for modern equipment.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 16

(a)

(b)

Program:	Breaker Replacement Program
Scope:	• Remove and replace at-risk breakers including • H breakers • Subtransmission breakers • Substation reclosers • Distribution breakers

(a)

(b)

Program:	Breaker Replacement Program				
Benefits:	• Enhance safety • Reduce major substation outage risk • Improve customer reliability • Avoid 2.9 M customer minute interruptions annually by 2026 • Avoid \$2.8 M costs annually for both circuit tree-related and non-tree related reactive capital by 2026 • Avoid further acceleration of breaker failures • Address most at risk breakers through aggressive prioritization				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x		x	x

(a)

(b)

Program:	Breaker Replacement Program			
Approximate Construction Schedule:	2023 - 29 units			
Budget Basis:	Project Management Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$9,549,052	\$ 0	\$ 0
	Material	\$2,963,639	\$ 0	\$ 0
	Other	\$648,505	\$ 0	\$ 0
	Total	\$13,161,195	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Cable Replacement Program
Purpose and Necessity:	DTE Electric distribution and subtransmission systems have around 3,200 miles of underground system cable. System cable is a critical component for both the subtransmission and distribution systems. A failure can interrupt a large number of customers for an extended period of time and remove important operational contingency. Approximately 43% of the system cable is identified as candidate for replacement.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 14

(a)

(b)

Program:	Cable Replacement Program
Scope:	• Prioritize and replace system cable based on multiple factors including cable type, vintage, previous failure history, impacts to the system, cable loading, and critical infrastructure customers • Remove underground hazards and replace defective conduits if needed

(a)

(b)

Program:	Cable Replacement Program				
Benefits:	• Reduce major substation outage risk • Avoid 0.6 M customer minute interruptions annually by 2026 • Avoid \$1.8 M costs annually for both circuit tree related and non-tree related reactive capital by 2026 • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x		x

(a)

(b)

Program:	Cable Replacement Program			
Approximate Construction Schedule:	2023 completed 42,608 ft (8.06 miles) 2024 target 54,395 ft (10.3 miles) 2025 target 59,687 ft (11.3 miles) 2026 target 65,000 ft (12.3 miles) 2027 target 65,000 ft (12.3 miles) 2028 target 65,000 ft (12.3 miles) 2029 target 65,000 ft (12.3 miles)			
Budget Basis:	• Avoid further acceleration of system cable failures • Focus on aging cable through aggressive prioritization			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$16,444,627	\$12,450,763	\$13,695,562
	Material	\$4,521,854	\$2,550,156	\$2,805,116
	Other	\$1,865,411	\$ 0	\$ 0
	Total	\$22,831,892	\$15,000,919	\$16,500,678

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Disconnect and Switcher Replacement
Purpose and Necessity:	Subtransmission disconnect switches are used to sectionalize and provide isolation points on the electrical system for operational reasons or for service and maintenance. Failures of disconnect switches during operation, when operators attempt to open or close a disconnect manually, can lead to safety concerns, reduce system operability, and force additional equipment to be taken out of service to allow critical work to continue. DTE Electric is replacing at risk subtransmission disconnect switches.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 21

(a)

(b)

Program:	Disconnect and Switcher Replacement
Scope:	• Replace at risk Cap & Pin and PM-40 disconnects

(a)

(b)

Program:	Disconnect and Switcher Replacement				
Benefits:	• Enhance safety • Improving system operability • Improve system reliability				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Disconnect and Switcher Replacement			
Approximate Construction Schedule:	Annual Program			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$12,210,026	\$4,638,667	\$4,671,596
	Material	\$3,247,219	\$261,333	\$228,404
	Other	\$ 0	\$ 0	\$ 0
	Total	\$15,457,245	\$4,900,000	\$4,900,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Frequent Outage Program (CEMI)
Purpose and Necessity:	•In order to select which circuits the Customer Excellence (CE) team will work on, an algorithm was developed to prioritize each circuit based on reliability performance. Considerations for the selection of circuits includes: customer complaints, the number of high-risk customers per circuit, tree trim cycles, the amount of planned or current work on a circuit, and AMI data for the previous 12-month period (rolling), taking into consideration the recency of reliability defects based on the collected AMI data. •Circuits that are selected for the CE team are analyzed to identify areas on the circuit with the highest reliability concerns. The circuits are then field patrolled to understand both equipment and tree conditions. Upon the completion of the patrol, a work package is developed and both tree work and overhead construction is scheduled immediately. The cycle time from circuit selection to field completion averages 2 months. •In addition to hot spot tree trimming and replacing defective equipment, the CE team also checks operating equipment to ensure it is functioning properly, conducts faults studies to ensure the circuits are fused properly, and installs equipment that will minimize outages such as reclosing devices and animal guards. •The customers on selected CE circuits receive communication throughout the CE process starting with an initiation email. The CE team coordinates with the Corporate Communication team to collect photos of work being conducted in the field and utilizes social media to update the progress of the reliability improvements. Once work is completed, customers receive a close-out email outlining the completed work.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 15

(a)

(b)

Program:	Frequent Outage Program (CEMI)
Scope:	• Replace defective equipment • Hot spot tree trim • Ensure operating equipment is functioning properly • Conduct faults studies to ensure the circuits are fused properly • Install equipment that will minimize outages such as reclosing devices and animal guards

(a)

(b)

Program:	Frequent Outage Program (CEMI)				
Benefits:	PROGRAM GOALS: Increase reliability by determining the equipment that needs to be replaced, installed or removed to eliminate outages, momentaries and voltage problems PROGRAM METRICS: SAIFI for the CE circuits decreased by 35.2%.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:				x	
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:			x	x	

(a)

(b)

Program:	Frequent Outage Program (CEMI)			
Approximate Construction Schedule:	Customer Excellence works throughout the year to improve reliability on the worst performing circuits. The workload is distributed as evenly as possible through the year. Less work is usually planned for completion in the summer months due to crews being			
Budget Basis:	Target number of circuits and engineering estimates of cost per circuit			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$53,289,862	\$40,484,457	\$52,662,816
	Material	\$10,673,488	\$7,565,287	\$9,841,045
	Other	\$ 0	\$ 0	\$ 0
	Total	\$63,963,350	\$48,049,745	\$62,503,861

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Mobile Fleet Program
Purpose and Necessity:	During system contingencies where portions of the distribution system may be expected to experience or is experiencing significant outages, voltage excursions or overloads, traditional solutions may take too long to implement and introduce outages or power quality issues to customers. There are also situations keeping a distribution asset online into a contingency condition places additional stress on the asset which may introduce failure, the portable generation equipment can reduce that strain and reduce the risk of a second failure occurring which would otherwise result in customer impacts including large extended outages. Portable equipment provides a rapid deployment solution to address the immediate need in an area while normal repairs or work is ongoing to provide a permanent resolution. When used to support the grid voltage or loading the mobile equipment is used to prevent an outage during a constrained time. The Mobile Fleet program (aka portable equipment) provides timely restoration to customers stranded during major outage events. The Mobile Fleet program also enables system shutdowns during planned capital construction and maintenance work to minimize customers affected or provide an additional margin to allow for jobs to be scheduled and completed when they otherwise would have to be deferred.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 2

(a)

(b)

Program:	Mobile Fleet Program
Scope:	• Procure portable emergency preparedness equipment and configure for rapid deployment according to DTEs operating practices. • Enhance existing mobile units with advanced controls and the ability to operate together seamlessly to reduce deployment time. • Integrate lessons learned from prior field deployments to enhance equipment and integrate new functionality requested by field crews or system operators and enhance safety and productivity of existing units • Design, test and implement new technology into mobile fleet to expand utilization and to serve a higher variety of events and use cases. • Integrate Nonwire alternative technologies into mobile fleet to provide additional benefits in reductions on emissions and noise.

(a)

(b)

Program:	Mobile Fleet Program				
Benefits:	• Mitigate major substation outage risk by reducing customer restoration time during major substation events • Improve system operability under contingency conditions or planned work • Maintain system voltage in contingency conditions or operate in islanded mode to maintain service during major events				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x			x

(a)

(b)

Program:	Mobile Fleet Program			
Approximate Construction Schedule:	2022 purchase and packaging of 3 commercial generator units, construction of small switching trailers, controls work on portable switchgear 2023 Initial PDG1 repackaging, construction of small switching trailers, controls work on portable switchgear			
Budget Basis:	Vendor quotations, prior project costs, Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$309,857	\$1,116,667	\$335,000
	Material	\$2,142,798	\$3,383,333	\$1,015,000
	Other	\$351,401	\$500,000	\$150,000
	Total	\$2,804,056	\$5,000,000	\$1,500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Pole and Pole Top Maintenance and Modernization (PTMM)
Purpose and Necessity:	DTE Electric owns more than 1 million distribution and subtransmission poles and attaches to nearly 200,000 poles owned by other utilities. In 2023, the average pole age in the DTEE system is approximately 47 years. The life expectancy of a pole is 40 years for wood pine poles and 50 years for wood cedar poles. The Pole and Pole Top Hardware programs are designed to identify and remediate poles with deteriorating strength and identify and replace defective pole top hardware prior to causing outages.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 13

(a)

(b)

Program:	Pole and Pole Top Maintenance and Modernization (PTMM)
Scope:	• Perform foot patrols to visually and physically inspect poles for signs of damage or rot, and to test mechanical strength • Reinforce or replace poles based on testing results • Perform foot patrols to visually inspect pole top hardware for signs of defective or damaged equipment • Replace defective or damaged pole top hardware

(a)

(b)

Program:	Pole and Pole Top Maintenance and Modernization (PTMM)				
Benefits:	• Comply with MPSC recommendation of inspecting poles on a 10-12 year cycle • Enhance safety • Avoid 40 M customer minute interruptions annually by 2026 • Avoid \$4.8 M costs annually for both circuit tree related and non-tree related reactive capital by 2026 • Invest in EJ communities				
Impact Dimension:	Reduce Electrical	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Pole and Pole Top Maintenance and Modernization (PTMM)			
Approximate Construction Schedule:	Annual Program			
Budget Basis:	• Adherence to the industry’s best practice of 10-12 year inspection cycle • Projected higher rejection rates during pole and pole top hardware inspection due to aging			
Total Estimated: \1	Program investments are excluded from total project cost calculations.			
Projected:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$57,599,478	\$46,218,151	\$88,138,633
	Material	\$17,186,973	\$13,790,925	\$26,299,479
	Other	\$4,288,260	\$3,440,924	\$6,561,888
	Total	\$79,074,711	\$63,450,000	\$121,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Pontiac Vaults
Purpose and Necessity:	Drivers for the Pontiac Vault project include the following: • Safety: The underground system contained fifteen system switching vaults. These (confined space) vaults, containing obsolete overhead equipment, are typically located beneath city sidewalks with surface mounted grates. Shock hazard to personnel entering the vaults and inadequate arc flash distance make it difficult or impossible to operate within the vaults. • Reliability: DTE is eliminating or upgrading the vaults. The project objective is to complete a redesign of system configuration, vault equipment replacement and structural reconditioning, and replacement of prevalent undersized, end of life cables. • Operability: Restoration time to an outage event was considerably extended due to system complexity and hazardous work environment conditions.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 17

(a)

(b)

Program:	Pontiac Vaults
Scope:	• Retrofit / upgrade twelve underground vaults. • Replace (7.4 miles) cable. • Redesign underground system configuration. • Remove live front overhead equipment from the below grade vaults and replace with dead front (arc flash contained) submersible equipment • Upgrade / repair structural condition of these vaults • Replace 39,167 feet of paper and lead cable with 500 EPR cable • Install SCADA communication / monitoring equipment

(a)

(b)

Program:	Pontiac Vaults				
Benefits:	• Enhance safety • Improve operability • Replace aging infrastructure and improve reliability • Reduce reactive cost by replacing obsolete, special-order equipment				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	X				

(a)

(b)

Program:	Pontiac Vaults			
Approximate Construction Schedule:	2017 – 2022 Conceptual, Design, Execution 2023 Complete Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$294,550	\$ 0	\$ 0
	Material	\$187,912	\$ 0	\$ 0
	Other	\$174,289	\$ 0	\$ 0
	Total	\$656,751	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	SCADA Pole Top Device Replacement
Purpose and Necessity:	This program targets two of the equipment types that have experienced high rates of failure - Eaton Form 3 reclosers and Bridges pole top switches (PTSs). Failures of these devices will result in reduced system operability and can cause customer interruptions.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 30

(a)

(b)

Program:	SCADA Pole Top Device Replacement
Scope:	• Replace end-of-life VWE Form 3 Reclosers with Form 6 Triple Single reclosers • Replace end-of-life PTSs with Second Generation S&C PTS

(a)

(b)

Program:	SCADA Pole Top Device Replacement				
Benefits:	- Increased reliability of the DTE Distribution Automation System and Telemetry back to SOC - Reduction of scope on the Pole Top Device Preventive Maintenance Program - Risk of SCADA equipment failures will lower, benefiting SOC with restorations and minimizing customer outages.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	SCADA Pole Top Device Replacement			
Approximate Construction Schedule:	Annual Program			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$895,042	\$955,206	\$1,076,948
	Material	\$799,112	\$852,828	\$961,521
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,694,154	\$1,808,034	\$2,038,469

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Station Upgrade: 120 kV Relays Upgrade for ITC Projects
Purpose and Necessity:	The ITC initiates work to upgrade the 120 kV relaying at points of interconnection (POI) with DTE. DTE becomes involved to support the ITC projects. This program upgrades obsolete DTE relays at lower cost than reactive work or planned capital work and avoids unfavorable shutdowns due to system out of normal configuration and/or system peak loads.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 33

(a)

(b)

Program:	Station Upgrade: 120 kV Relays Upgrade for ITC Projects
Scope:	The most common change unit will be upgrading a stepdown or distribution transformer's protection in which an existing panel or two is/are replaced with one specification panel. Some projects include two or more units. Exceptions from a standard relay panel are relay plates for distribution switchgears. Projects to be constructed in 2024: Wayne (1), Sloan (1), Stephens (1), Red Run (2) Projects to be constructed in 2025: Hager (2), Duval (2), Dorset (1), Bloomfield (1)

(a)

(b)

Program:	Station Upgrade: 120 kV Relays Upgrade for ITC Projects				
Benefits:	1) Work will be conveniently planned, designed and executed during off peak loads in cooperation with ITC. 2) As being planned work, the timelines of project under this program will not impact the timelines of ongoing projects. 3) Replacing transformers panels during a shutdown for an ITC driven project will avoid a separate future shutdown. 4) The smart microprocessor relays generate alarms, LEDs, and time-stamped event reports for troubleshooting and maintenance targets, hence avoiding outages or reducing outage durations. 5) Additional design is established in selected same protective relay to provide enhanced remote control. This came timely with the SCADA relay not being available anymore. 6) Relay failure alarms provide advanced notice to replace the failed relay before an actual event without a shutdown due to redundancy in the protective scheme. 7) The relaying upgrades will contribute to strengthening the Electric Grid.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Station Upgrade: 120 kV Relays Upgrade for ITC Projects			
Approximate Construction Schedule:	**Typical timeline per unit: 45 Days: ITC Initiates Project with DTE, 60-90 Days: Relay Design 90-120 Days: Substation Design Protective Relaying & Controls, 54 Days: Panel Fabrication, 35 Days: Construction, 120 Days: Closeout Yearly schedule			
Budget Basis:	Engineering Estimate; ITC planning horizon			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$937,505	\$1,992,372	\$2,283,230
	Material	\$421,004	\$705,243	\$201,588
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,358,509	\$2,697,615	\$2,484,818

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Station Upgrade: Lincoln
Purpose and Necessity:	Existing 24kV relay panels are marble and cannot be maintained or modified when relay upgrades are needed. There is not enough space to install new panels so a new configuration is needed to create space. Existing relays are nearly 60 years old and obsolete. There are at risk breakers, disconnects, and other equipment. Replacements of the breakers and disconnects are challenging due to space constraints. A comprehensive station upgrade is needed to address these issues.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 29

(a)

(b)

Program:	Station Upgrade: Lincoln
Scope:	• Replace (14) 24 kV oil circuit breakers with gas circuit breakers • Replace existing relay panels with 20 new microprocessor-based relay panels • New relay panels include three bus panels and one under frequency panels

(a)

(b)

Program:	Station Upgrade: Lincoln				
Benefits:	• Remove at risk relays • Improve grid-wide situational awareness • Enable SCADA, fault detection, and metering capabilities in substations • Enable remote modification on relay settings can be applied remotely, resulting in fewer field visits • Reduce reactive costs during non-storm and storm events • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Station Upgrade: Lincoln			
Approximate Construction Schedule:	2025 - engineering and design 2026 - begin construction 2027 - complete construction			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 9,835,596			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$330,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$330,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Station Upgrade: Navarre
Purpose and Necessity:	Existing 24kV relay panels are marble and cannot be maintained or modified when relay upgrades are needed. There is not enough space to install new panels so a new configuration is needed to create space. Existing relays are nearly 60 years old and obsolete. There are at risk breakers, disconnects, and other equipment. Replacements of the breakers and disconnects are challenging due to space constraints. A comprehensive station upgrade is needed to address these issues.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 32

(a)

(b)

Program:	Station Upgrade: Navarre
Scope:	• Replace (20) 24 kV oil circuit breakers with gas circuit breakers • Replace existing relay panels with 35 new microprocessor-based relay panels • New relay panels include three bus panels and one under frequency panels

(a)

(b)

Program:	Station Upgrade: Navarre				
Benefits:	• Remove at risk relays • Improve grid-wide situational awareness • Enable SCADA, fault detection, and metering capabilities in substations • Enable remote modification on relay settings can be applied remotely, resulting in fewer field visits • Reduce reactive costs during non-storm and storm events • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Station Upgrade: Navarre			
Approximate Construction Schedule:	2024 - engineering and design 2025 - begin construction 2026 - complete construction			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 9,830,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$330,000	\$4,359,710
	Material	\$ 0	\$ 0	\$940,290
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$330,000	\$5,300,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Station Upgrade: Northeast (Relay Replacement)
Purpose and Necessity:	Existing 24kV relay panels are marble and cannot be maintained or modified when relay upgrades are needed. There is not enough space to install new panels so a new configuration is needed to create space. Existing relays are nearly 60 years old and obsolete. There are at risk breakers, disconnects, and other equipment. Replacements of the breakers and disconnects are challenging due to space constraints. A comprehensive station upgrade is needed to address these issues. In addition, ITC is upgrading their 120 kV bus relaying and removing high speed protection for the transformers. DTE needs to add that functionality by installing new relay panels.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 24

(a)

(b)

Program:	Station Upgrade: Northeast (Relay Replacement)
Scope:	• Replace (21) 24 kV oil circuit breakers with gas circuit breakers • Replace existing relay panels with 37 new microprocessor-based relay panels • New relay panels include three bus panels and one under frequency panel

(a)

(b)

Program:	Station Upgrade: Northeast (Relay Replacement)				
Benefits:	• Remove at risk relays • Improve grid-wide situational awareness • Enable SCADA, fault detection, and metering capabilities in subtransmission stations • Enable remote modification on relay settings can be applied remotely, resulting in fewer field visits • Reduce reactive costs during trouble				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Station Upgrade: Northeast (Relay Replacement)			
Approximate Construction Schedule:	Construction in 2022 and 2023			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 19,888,076			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,156,136	\$ 0	\$ 0
	Material	\$562,105	\$ 0	\$ 0
	Other	\$933,545	\$ 0	\$ 0
	Total	\$3,651,786	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Station Upgrade: Warren (Relay Replacement)
Purpose and Necessity:	Existing 24kV relay panels are marble and cannot be maintained or modified when relay upgrades are needed. There is not enough space to install new panels so a new configuration is needed to create space. Existing relays are nearly 60 years old and obsolete. There are at risk breakers, disconnects, and other equipment. Replacement of the breakers and disconnects are challenging due to space constraints. A comprehensive station upgrade is needed to address these issues. In addition, ITC is upgrading their 120 kV bus relaying and removing high speed protection for the transformers. DTE needs to add that functionality by installing new relay panels.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 23

(a)

(b)

Program:	Station Upgrade: Warren (Relay Replacement)
Scope:	• Replace (21) 24 kV oil circuit breakers with gas circuit breakers • Replace existing relay panels with 43 new microprocessor-based relay panels • New relay panels include three bus panels and one under frequency panel

(a)

(b)

Program:	Station Upgrade: Warren (Relay Replacement)				
Benefits:	• Remove at risk relays • Improve grid-wide situational awareness • Enable SCADA, fault detection, and metering capabilities in subtransmission stations • Enable remote modification on relay settings can be applied remotely, resulting in fewer field visits • Reduce reactive costs during trouble				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Station Upgrade: Warren (Relay Replacement)			
Approximate Construction Schedule:	2022: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 11,276,899			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$649,083	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$649,083	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Steel Pole Highway Crossings
Purpose and Necessity:	DTE equipment has been subject to incidents that have resulted in collapse of overhead freeway or highway crossing power equipment. This program was developed to replace all wood poles with steel poles at these crossings as part of a multi-year program that is expected to replace and rebuild 53 crossings.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 22

(a)

(b)

Program:	Steel Pole Highway Crossings
Scope:	For the future installations of steel poles at freeway or highway crossings, the following work will be needed. • 2-4 poles to be replaced with new steel poles at each crossing. • Approximately 400-600 feet of OH conductor to be replaced at each crossing • 636 AL or 945 ACSR Conductor will be used for Subtransmission lines • Distribution lines and Communication lines will be replaced, as necessary

(a)

(b)

Program:	Steel Pole Highway Crossings				
Benefits:	- Switching from wood to steel poles increases reliability of the structure. - Design stress limited to 75% for increased strength at crossings - Damage limiter structures at or near the crossings will be required to prevent cascading failures - Re-designing the crossings will allow us the ability to ensure the crossings have adequate strengths due to the addition of joint use post initial design - Pending: Installation of an overhead conduit to receive a future DTE communication fiber				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Steel Pole Highway Crossings			
Approximate Construction Schedule:	Annual program			
Budget Basis:	Project Management Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,410,243	\$4,103,720	\$4,400,000
	Material	\$323,894	\$896,280	\$600,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,734,137	\$5,000,000	\$5,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Regulator Replacement
Purpose and Necessity:	Substation regulators are used to maintain voltages within a normal range. Through Asset Health Assessments, DTE has identified induction, tri-delta and tri-wye type regulators as being obsolete with technology that is no longer manufactured or supported. An increasing number of issues are occurring with these types of units with repair time continuing to increase due to a need to dry out the insulation in the units and repair or replace voltage controls. Replacement of these units will allow for proper voltage regulation.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 31

(a)

(b)

Program:	Substation Regulator Replacement
Scope:	• Replace obsolete three-phase substation regulators (tri-delta, tri-wye, or induction) with new three-phase step regulators.

(a)

(b)

Program:	Substation Regulator Replacement				
Benefits:	• Allow for proper voltage regulation at those substations and avoid out-of-range voltage that could damage customer equipment or cause reliability problems • Eliminate aging infrastructure				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Substation Regulator Replacement			
Approximate Construction Schedule:	Annual Program			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$130,373	\$570,771	\$569,978
	Material	\$792,473	\$245,326	\$251,772
	Other	\$413,706	\$ 0	\$ 0
	Total	\$1,336,552	\$816,097	\$821,750

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Apache
Purpose and Necessity:	The switchgear at Apache substation is at-risk at needs to be preplaced to prevent another switchgear failure. Drivers for this project include the following:' Safety: Apache substation switchgear is at risk of failure Operability: In 2015, a breaker position failure at Apache Substation caused a significant area-wide outage for the entire substation area. The downtown business district of Troy and the surrounding commercial/residential area were without electrical service for several days. This switchgear was classified as at-risk Reliability: The switchgear needs to be replaced to prevent a second switchgear failure. A switchgear failure could result in loss of all switchgear positions and a potential of stranded load of up to 16 MVA.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 6

(a)

(b)

Program:	Substation Risk: Apache
Scope:	• Replace existing 19 position switchgear with two 12 position switchgear • Replace three circuit switchers with three new S&C 2020 circuit switchers • Build system cable termination on new switchgear for all 13 distribution circuits • Decommission/remove existing 19 position switchgear once all load is cut over to new switchgear • Install 1,440 feet of conduit including one 2-way manhole and nine 3-way manholes • Remove ~8,584 feet of cable • Install ~9,333 feet of cable • Replace nineteen disconnect switches with manual pole top switches at station cable poles

(a)

(b)

Program:	Substation Risk: Apache				
Benefits:	• Reduce substation outage risk due to switchgear failure and stranded load upwards to 16.0 MVA by replacing aging infrastructure and failed equipment. • Future opportunity to relieve Apache Substation circuits that exceed day to day circuit limits • Distribution System capacity increase: 34%				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Substation Risk: Apache			
Approximate Construction Schedule:	2021 Conceptual & detailed engineering Site plan approval from City of Troy 2022 Station Construction Conduit & Cable Design 2023-2024 Complete Station Construction Conduit & Cable Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 19,740,974			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$6,198,617	\$2,572,932	\$ 0
	Material	\$1,428,559	\$1,237,419	\$ 0
	Other	\$864,399	\$ 0	\$ 0
	Total	\$8,491,575	\$3,810,351	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Belleville Switchgear Decommission
Purpose and Necessity:	Belleville 4.8 kV Substation has three load carrying circuits and one throwover circuit. This project is required to eliminate the end-of-life 4.8 kV switchgear by using Nova Triple Single reclosers and reconfiguring and consolidating the circuits into two load carrying circuits. Drivers for the project include the following: • Safety: The switchgear is at end-of-life and there are no replacements for breakers if they were to fail. The automatic throwover between the two 4.8 kV buses is currently disabled due to breaker mis-operation. The control wiring in every position is falling apart and requires weeks of work to re-wire. • Reliability: Not completing this work will lead to extended outages and the need to utilize portables or diesel generators to maintain service. • Capacity: Belleville Substation is at 102% of firm. • Operability: The switchgear experienced a failure in 2022 during the project which condemned Bus 11 and limited jumpering options.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 8

(a)

(b)

Program:	Substation Risk: Belleville Switchgear Decommission
Scope:	• This work will bypass BELVL's 4.8 kV switchgear by installing overhead NOVA Triple-Single reclosers just outside of the substation. • The 4.8 kV portion of BELVL substation will be converted from a Class 'A' to a Class 'T' operating at 4.8 kV. • Reconfigure the 3 load carrying circuits and throw over circuit into 2 load carrying circuits

(a)

(b)

Program:	Substation Risk: Belleville Switchgear Decommission				
Benefits:	• Reduce substation outage risk by eliminating aging infrastructure				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				x

(a)

(b)

Program:	Substation Risk: Belleville Switchgear Decommission			
Approximate Construction Schedule:	Construction in 2022 and 2023			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,849,868			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,284,784	\$ 0	\$ 0
	Material	\$ 28,666	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,313,450	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Chestnut
Purpose and Necessity:	Chestnut substation is a 120-13.2 kV substation serving ~11,000 customers. The project will reconfigure the substation, replace high risk equipment and eliminate the potential for a single point of failure. Drivers for the project include the following: • Reliability: Due to age of equipment and configuration, Chestnut substation is at risk. The switchgear is at high risk of failure (over 50 years old) and the breakers are at very high risk of failure. • Operability: There are limited jumpering options, leaving a significant stranded load of 35 MVA, affecting about 6,000 customers in Madison Heights, Troy, and Royal Oak area
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 4

(a)

(b)

Program:	Substation Risk: Chestnut
Scope:	• Replace existing 19-position Switchgear with (2) 12-position Power Delivery Centers • Replace and relocate three (3) capacitor banks • Install 500 feet of concrete encased duct bank • Install (4) new manholes • Install (2) miles of System Cable & associated branch and straight joints • Install (17) sectionalizing devices

(a)

(b)

Program:	Substation Risk: Chestnut				
Benefits:	• Reduces 35 MVA of stranded load exposure • Drastically reduce the risk of stranded load due to catastrophic equipment failures • Lowers probability of high-profile customers experiencing long duration outages • Provides additional 13.2 kV distribution circuit positions for future use • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Substation Risk: Chestnut			
Approximate Construction Schedule:	2021: Engineering 2021-2022: Detailed Design 2023-2024: Construction			
Budget Basis:	Alternatives Considered			
Total Cost: \1	The estimated project cost for this investment is \$ 15,988,931			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$915,894	\$2,725,375	\$4,463,780
	Material	\$ 73,420	\$ 0	\$2,250,704
	Other	\$ 0	\$ 0	\$1,166,369
	Total	\$989,314	\$2,725,375	\$7,880,853

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Drexel
Purpose and Necessity:	Drexel substation experienced a failure in Position I which caused major damage to the surrounding positions. As a result, Bus 11 and Bus 12 at Drexel substation were decommissioned and the load was jumpered to surrounding substations. This project will restore Drexel substation and its circuits to their original configuration.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 3

(a)

(b)

Program:	Substation Risk: Drexel
Scope:	• Decommission and remove the damaged switchgear lineup • Install nine position switchgear • Install one 15/20/25 MVA transformer to feed the new switchgear • Install 6900 feet of EPR cable from new switchgear lineup to existing cable poles • Restore circuits to pre-fire configurations

(a)

(b)

Program:	Substation Risk: Drexel				
Benefits:	• Reduce substation outage risk by replacing aging infrastructure and failed equipment				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Substation Risk: Drexel			
Approximate Construction Schedule:	2023: complete circuit transfers to new switchgear			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 9,173,970			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$182,865	\$ 0	\$ 0
	Material	\$ 20,696	\$ 0	\$ 0
	Other	\$436,902	\$ 0	\$ 0
	Total	\$640,463	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Flood Defense Program
Purpose and Necessity:	Some substations constructed in the 1930s and 1940s have distribution assets located below ground in basements. These older substations utilize water cooled transformers and other equipment which requires a sewer connection. The basements at both McGraw and Scotten substations flooded with water causing equipment damage and loss of load. Record heavy rainfall and capacity malfunctions at nearby pump stations have contributed to the substation flooding.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 11

(a)

(b)

Program:	Substation Risk: Flood Defense Program
Scope:	• Installation/maintenance of one-way backflow prevention valves on existing sewer connected dewatering system. • Installation/maintenance of emergency dewatering pump to discharge at ground level during a sewer backup condition. • Sealing/maintenance of conduit penetrations. • This will be done at 5 Substations (SCOTN, FRISB, WALKR, MADSN, & ORCHD) • A as-is risk analysis will be done for MCGRW substation.

(a)

(b)

Program:	Substation Risk: Flood Defense Program				
Benefits:	Protection of major equipment located in the basement of substations that are prone to flooding which can potentially disrupt service.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Substation Risk: Flood Defense Program			
Approximate Construction Schedule:	2023: Engineering, design 2024: Construction			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 231,191	\$4,795,491	\$ 0
	Material	\$ 17,563	\$213,598	\$ 0
	Other	\$ 20,192	\$ 0	\$ 0
	Total	\$268,946	\$5,009,089	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Hood
Purpose and Necessity:	This project will decommission the skid mounted HOOD substation and build a two transformer 13.2 kV substation at its location. Drivers for this project include the following: Safety: The skid mount substation transformer failed and has been determined to be at risk. Operability: Hood substation is a skid mounted substation with two load carrying circuits. It serves over 2,000 customers. The skid mount transformer recently failed and there was no spare unit available. The customers are temporarily transferred to BLMFD DC 8891 until the HOOD substation project is completed. Bloomfield (BLMFD) substation is supported by at-risk switchgear and the substation is to be decommissioned. Reliability: The load on HOOD has been temporary jumpered to Bloomfield substation to facilitate construction at HOOD substation. In case of failure at Bloomfield substation, the load will be stranded.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 26

(a)

(b)

Program:	Substation Risk: Hood
Scope:	• Replace substation infrastructure. • Extend (0.1 miles) conduit. • Extend (0.3 miles) cable. • Install six Pole Top Switches. • Remove failed skid-mount substation and Portable ready infrastructure. • Construct a new two transformer (2-15/20/25MVA transformers, two modular PDC) substation • Extend ~ 220 ft of 2-5" conduit • Extend ~720 ft of 750 EPR cables • Install six PTS to support station cable poles

(a)

(b)

Program:	Substation Risk: Hood				
Benefits:	Added benefit: Proposed replacement increases capacity for the area, from 13 to 40.2 MVA. Substation upgrade supports CC Pontiac conversion by establishing two additional HOOD circuits. Accelerates conversion and transfer from failing 8.3 kV infrastructure				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Substation Risk: Hood			
Approximate Construction Schedule:	2022-2023 Conceptual, Design, Execution 2024-2025 Complete Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 8,145,117			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$248,780	\$4,006,211	\$651,916
	Material	\$ 0	\$2,912,182	\$326,028
	Other	\$ 0	\$ 0	\$ 0
	Total	\$248,780	\$6,918,393	\$977,944

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Imlay
Purpose and Necessity:	This project will upgrade OTSGO substation and decommission 4.8 kV IMLAY substation which has safety and space constraint concerns. Drivers for the project include the following: Safety: The Imlay substation site has several safety concerns. The substation is not built to Company standards. The site is small and there is not space to rebuild any equipment. Due to the size of the site, there are concerns regarding clearances which may pose a safety risk to workers at the site. The site has poor lighting making it difficult to operate equipment in the dark. The proximity of the equipment is a concern when maintaining the equipment. The site is also built on different elevations, making any kind of retrofit or upgrade very difficult. Reliability: - IMLAY average SAIFI from 2019 to 2022 is 1.85 - IMLAY average SAIDI from 2019 to 2022 is 548.25 - IMLAY average CAIDI from 2019 to 2022 is 344.75 Capacity: To make capacity for IMLAY load, the OTSGO/CAPAC load relief project must be completed. Operability: IMLAY DC 0301 and IMLAY DC 0302 do not have automatic loop schemes. There are limited jumpering options for IMLAY load.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 36

(a)

(b)

Program:	Substation Risk: Imlay
Scope:	• Upgrade (1) existing substation • Rebuild (30) miles of existing overhead conductor • Convert (30) miles of existing overhead conductor • Decommissioning (1) existing substation

(a)

(b)

Program:	Substation Risk: Imlay				
Benefits:	With the upgrades/expansion at OTSGO Class 'R' substation, we will be able to decommission the distribution substation IMLAY to address some of the safety and operability concerns. Will convert another 30 miles of 4.8 kV distribution to 13.2 kV and consolidate double build OH distribution. Keep OTSGO below 80% of FIRM and allow the removal of LTBT blocking scheme at OTSGO. No additional property required to convert and move load from IMLAY substation after the completion of OTSGO/CAPAC capital project.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:				x	x

(a)

(b)

Program:	Substation Risk: Imlay			
Approximate Construction Schedule:	Schedule is based on assumption that OTSGO/CAPAC project will be provided enough funding to remove required load to allow for IMLAY load to be added. 2025: Engineering & Design 2025 - 2030: OH Pre-conversion 2028 - 2030: OH Conversion 2028 - 2030: Decommissioning			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 38,766,721			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$100,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$100,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: McGraw
Purpose and Necessity:	McGraw Substation is a Class C, in-building, multi-level substation located at the border of Detroit and Dearborn and serves customers in both cities. In June 2021, flooding in the McGraw substation affected/condemned associated position breakers, busses, transfer busses and house service panels that reside in the basement floor which caused a catastrophic, total loss of the substation’s ability to distribute electricity and interrupted service for over 7,000 customers. These customers were restored and are currently being served through temporary means including disaster cable at the substation and in a field adjacent and a portable substation and diesel generators staged in public rights of way and private property. The primary objectives of the McGraw Flood Mitigation initiative are to eliminate future reliability impacts from flooding and to return our customers back to normal utility service as soon as possible. Safety: Energized disaster cable at the substation and large portable equipment staged in public rights of way poses safety risk to employees and public. A significant vehicle accident has already disrupted service to customers fed from the portable substation Reliability: 7,000 customers are fed from temporary sources (emergency pole farm, portable substations, diesel generators) that do not have the same level of reliability and power quality that a permanent utility feed would offer. (gang operated breakers, reclosing, N-1 automatic throwover within substation, etc.) Capacity: There is no ability to add additional customer connections to McGraw until permanent service is restored Operability: For the customers served from the temporary emergency pole farm, In the event of substation transformer or 24kV failures, N-1 operating capability is limited to manual operation, and additional outages/power quality issues would occur for these events until switching could occur, for customers served from diesel generation, outages due to generator trip off would also require manual operation to restore. If the portable substation was to fail, generators would need to be deployed to restore those customers.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 9

(a)

(b)

Program:	Substation Risk: McGraw
Scope:	• Acquire property adjacent to McGraw sub to and construct external portion of new substation • Perform permanent load overhead load transfers on (2) McGraw circuits (2,000 customers) to adjacent substations and install sectionalizing equipment to maintain pre-event reliability to customers • Construct a (2) Transformer 24/4.8 kV substation with (1) 9-position switchgear on the adjacent property to place 4,000 customers back on permanent service • Replace all remaining basement infrastructure (8 position breakers) on the second floor of existing McGraw and re-route cabling within the substation to place the remaining 1000 customers back on permanent service • Acquire parcels and vacated ROW from the City of Detroit and MDOT adjacent to McGraw to allow exterior expansion • DC 1280 MCGRW: Cascade load from DC 1119 SHADK to DC 1093 SHADK (~1.2MVA). Transfer load of DC 1280 MCGRW to DC 1119 SHADK. Install (1) set 250kVA open delta regulators. Install sectionalizing & protection as necessary to facilitate load transfers and maintain reliability. Decommission DC 1280 MCGRW station cable and position. • DC 1366 MCGRW: Transfer load to DC 2113 WAGNR. Install sectionalizing & protection as necessary to facilitate load transfers and maintain reliability. • Decommission MCGRW PL132 AND MCGRW PL96. Make load transfers permanent from MCGRW PL132 to MCGRW PL612 and MCGRW PL96 to MCGRW PL416 • Install a 9-position PDC and (2) 24/4.8 kV transformers and associated disconnects, conduit, cable, lightning masts and oil containment. The PDC will be decommissioned and removed from SPKNE substation and repurposed for McGraw with necessary repairs and upgrades. • The expanded site will be graded and prepped and have below grade ground mat installed as well as +/- 600' 2x2 5" conduit for 24kV feeds to transformers as well as (2) manholes and +/- 400' 3x3 5" conduit for 4.8 kV circuit exits. A +/- 700' perimeter pre-cast wall will be erected around the site and some relocation of existing utilities (catch basins, storm lines, billboard) will be required.

(a)

(b)

Program:	Substation Risk: McGraw
	• Five circuits and a throw-over will have +/- 700' 750CU PL replaced or installed with EPR cable to the new PDC and will intercept existing circuit routes in McGraw Street. System neutral will be installed where required • Trunk 668T will be recabled with +/- 12,000' of 600EPR and tapped to feed MCGRW Class S. Trunk 612T will be tapped to feed MCGRW Class A. • Decommission and remove all reactors on second floor of McGraw and install eight position breakers and two tie-breakers. • Utilize regulator bays to route cable from second floor back to sub-basement for eight positions. • Break down cable in subbasement and install (8) transition joints to outgoing circuits

(a)

(b)

Program:	Substation Risk: McGraw				
Benefits:	This work will place 7,000 McGraw customers back on normal utility service and eliminate future flooding risk to substation				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x		

(a)

(b)

Program:	Substation Risk: McGraw			
Approximate Construction Schedule:	Land Acquisition (-01): City of Detroit Parcels acquired, MDOT parcels Target 2/12/2024 completion Load Transfers (-02): Complete infield. Finish construction 09/30/22. Substation Addition (-03): Design ~90% complete. Start construction 2/13/2024,			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 51,496,903			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,860,569	\$25,892,598	\$ 0
	Material	\$556,510	\$7,328,367	\$ 0
	Other	\$2,892,526	\$4,631,035	\$ 0
	Total	\$6,309,605	\$37,852,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Port Huron
Purpose and Necessity:	Safety: Exposed energized equipment at PTHUR causes safety concerns for those working on site. Reliability: Breakers at the substation have reached an "at risk" level, and may cause reliability issues. Operability: PTHUR has limited jumpering options. Exposed energized equipment at PTHUR causes operability concerns as equipment must be deenergized for any work to be complete.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 7

(a)

(b)

Program:	Substation Risk: Port Huron
Scope:	• Install (1) new Switchgear • Install new cables for new switchgear • Decommission and remove at-risk equipment

(a)

(b)

Program:	Substation Risk: Port Huron				
Benefits:	- Eliminate safety issues and operating constraints - Reduce substation outage risk by replacing aging infrastructure and failed equipment				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				x

(a)

(b)

Program:	Substation Risk: Port Huron			
Approximate Construction Schedule:	Project was completed in 2023.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 7,093,864			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 3,139	\$ 0	\$ 0
	Material	\$ 60	\$ 0	\$ 0
	Other	\$ 123	\$ 0	\$ 0
	Total	\$ 3,322	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Savage
Purpose and Necessity:	Drivers for the Savage stranded load project include the following: Safety: Risk of substation equipment failure Reliability: Possibility of stranded load is estimated at 30 MVA after possible load transfers and mobile fleet deployments Operability: Savage substation has high substation outage risk. This project is to address the substation outage risk at Savage substation. In addition, it will establish means for jumper point connections to circuits from neighboring substations.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 5

(a)

(b)

Program:	Substation Risk: Savage
Scope:	• Extend (0.1 miles) conduit. • Extend (0.7 miles) cable. • Replace (0.1 miles) overhead. • Extend 770 feet of conduit and 3,489 feet of cable to feed seven new primary switch cabinets and overhead connections. • Extend overhead 770 feet to establish two portable ready locations • Install two sets of 3-333 KVA regulators

(a)

(b)

Program:	Substation Risk: Savage				
Benefits:	- Reduce substation outage risk by replacing aging infrastructure and failed equipment - Enhance safety and operability				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Substation Risk: Savage			
Approximate Construction Schedule:	Completed in 2023			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,631,389			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 10,379	\$ 0	\$ 0
	Material	\$ 198	\$ 0	\$ 0
	Other	\$ 407	\$ 0	\$ 0
	Total	\$ 10,984	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Savage Switchgear Replacement
Purpose and Necessity:	This project will replace at-risk substation equipment. Drivers for the project include the following: Safety: Risk of substation equipment failure Reliability: Possibility of stranded load is estimated at 30 MVA after possible load transfers and mobile fleet deployments Operability: Savage substation has high substation outage risk. This project is to address the substation outage risk at Savage substation. In addition, it will establish means for jumper point connections to circuits from neighboring substations.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 34

(a)

(b)

Program:	Substation Risk: Savage Switchgear Replacement
Scope:	• Expand substation fence. • Replace switchgear. • Remove existing parking area north of existing substation fence (under lease agreement) – approximately 7800 sq. ft. • Extend substation fence (approximately 300 feet) and landscaping. • Perform site prep and below grade for expanded substation yard (122 x 75 ft) • Install concrete pads for new switchgear and three 6 MVAR Bus Capacitor banks • Install two 9-position 2-high switchgear (12 Circuits positions available) • Remove existing (1967's) continuous line-up of 16-position switchgear at Savage substation

(a)

(b)

Program:	Substation Risk: Savage Switchgear Replacement				
Benefits:	• Reduce major substation outage risk and improve customer reliability • Enhance safety and operability for employees working on and around the substation • Reduce reactive costs associated with recurrent sub-transmission outage events				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Substation Risk: Savage Switchgear Replacement			
Approximate Construction Schedule:	2026: Conceptual & detailed engineering site plan approval from City of Troy 2027: Complete Station Construction Conduit & Cable Construction			
Budget Basis:	Project Management Estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 10,040,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$100,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$100,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Seville
Purpose and Necessity:	This project involves the replacement of the switchgear at Seville substation. Drivers for the project include the following: Operability: Position B at Seville substation is inoperable, irreparable, and the load on Position B (SEVLE DC 9364) will be transferred to surrounding circuits. In doing so, this will limit the ability to transfer more load in case of failures. The Seville switchgear does not have any spare positions to establish a new circuit. Capacity: Due to this abnormal configuration, the switchgear at SEVLE substation will need to be replaced as both SEVLE DC 9367 and SEVLE DC 9359 are within 83% and 96% of their day-to-day ratings respectively Safety: Position B at Seville substation is inoperable and irreparable Reliability: Reduction in jumpering points due to transferring load to neighboring circuits.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 35

(a)

(b)

Program:	Substation Risk: Seville
Scope:	This is preliminary scope and will be refined during detailed engineering. • Removal of existing PDC (power delivery center) • Installation of new PDC • New transformer secondary cables to new PDC • New circuit cable to new PDC • Load transfers among SEVLE circuits • Load transfers to restore SEVLE circuits back to their original reconfiguration

(a)

(b)

Program:	Substation Risk: Seville				
Benefits:	Operability and loadability: - Seville circuits will return to their normal configuration, eliminating temporary violations caused by emergency load transfers. - New nine position PDC to replace old seven position PDC, will provide the capability to establish two new future distribution circuits to support future load growth.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	Substation Risk: Seville			
Approximate Construction Schedule:	2024: Engineering 2025: Substation Design and Underground Design 2026: Substation Construction, Underground Construction, Overhead Design, and Overhead Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,909,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$243,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$243,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	Substation Risk: Voyager
Purpose and Necessity:	Reliability: Existing motor disconnects at Voyager Substation are aging and outdated. The customer has expressed reliability concerns recently with DTE. This project will help improve the reliability for this customer.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 10

(a)

(b)

Program:	Substation Risk: Voyager
Scope:	• Install 4 piers & below grade for future circuit switchers

(a)

(b)

Program:	Substation Risk: Voyager				
Benefits:	• Improved customer reliability • Takes advantage of customer downtime to complete below grade work to facilitate the future replacement of the circuit switchers				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x		

(a)

(b)

Program:	Substation Risk: Voyager			
Approximate Construction Schedule:	2022: Construction			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 202,280			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 1,602	\$ 0	\$ 0
	Total	\$ 1,602	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

(a)

(b)

Program:	URD Replacement Program
Purpose and Necessity:	DTE Electric has approximately 11,000 miles of underground residential distribution (URD) cable, of which approximately 41% (4,500 miles) is cross-linked polyethylene (XLPE) cable installed prior to 1985. This cable is prone to high failure rates due to a manufacturing flaw known as "water treeing"; which is a breakdown of the insulation that allows water to enter the cable and causes faults. All cable insulation will breakdown eventually as URD cable is typically direct buried and more susceptible to environmental interference. As URD cable ages, the number of failures increases. In addition, after the URD loop has experienced one failure, the risk for a second failure also goes up. The average age of DTE Electric's URD cable is 28 years.
Category:	Infrastructure Resilience and Hardening
Line Number:	Exhibit A-12, Schedule B5.4, Page 13, Line 18

(a)

(b)

Program:	URD Replacement Program
Scope:	• Prioritize and replace pre-1985 non-tree retardant URD cable based on multiple factors including previous failure history, impacts to the system and customers, loading, and partial discharge testing results • Replace live front transformers with dead front (arc flash contained)

(a)

(b)

Program:	URD Replacement Program				
Benefits:	• Enhance safety by replacing live front transformers with dead front transformers • Avoid 5 M customer minute interruptions annually by 2026 • Avoid \$4.4 M costs annually for both circuit tree related and non-tree related reactive capital by 2026				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x		x	x

(a)

(b)

Program:	URD Replacement Program			
Approximate Construction Schedule:	Annual Program			
Budget Basis:	• Manage URD cable failures and avoid an acceleration of asset failures			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$11,690,951	\$ 0	\$ 0
	Material	\$725,866	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$12,416,817	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Investment Recovery Mechanism.

Investment	Page	Capital Exhibit Reference
4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	7	Exhibit A-12, Schedule B5.4, Page 15, Line 41
4.8 kV CC: Ariel Substation and Circuit Conversion.....	11	Exhibit A-12, Schedule B5.4, Page 15, Line 38
4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	15	Exhibit A-12, Schedule B5.4, Page 16, Line 86
44.8 kV CC: Buckler Circuit Conversion	19	Exhibit A-12, Schedule B5.4, Page 15, Line 42
4.8 kV CC: Calla Circuit Conversion and Phase 2	23	Exhibit A-12, Schedule B5.4, Page 16, Line 84
4.8 kV CC: Cortland / Oakman / Linwood Consolidation	27	Exhibit A-12, Schedule B5.4, Page 15, Line 37
4.8 kV CC: Crestwood Substation	31	Exhibit A-12, Schedule B5.4, Page 15, Line 48
4.8 kV CC: Curtis	35	Exhibit A-12, Schedule B5.4, Page 15, Line 55
4.8 kV CC: GRFIN & WMSTN Conversions	39	Exhibit A-12, Schedule B5.4, Page 15, Line 51
4.8 kV CC: Hawthorne Relief and Circuit Conversion	43	Exhibit A-12, Schedule B5.4, Page 15, Line 47
4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	48	Exhibit A-12, Schedule B5.4, Page 16, Line 88
4.8 kV CC: Hilton Substation and Circuit Conversion	52	Exhibit A-12, Schedule B5.4, Page 15, Line 54
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade.....	56	Exhibit A-12, Schedule B5.4, Page 15, Line 40
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade	60	Exhibit A-12, Schedule B5.4, Page 15, Line 39
4.8 kV CC: ISO Conversion Program	64	Exhibit A-12, Schedule B5.4, Page 16, Line 87
4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	68	Exhibit A-12, Schedule B5.4, Page 16, Line 85
4.8 kV CC: MAUME 8241 Downtown Clawson Conversion.....	72	Exhibit A-12, Schedule B5.4, Page 15, Line 49
4.8 kV CC: McKinstry Sub Decommission.....	76	Exhibit A-12, Schedule B5.4, Page 15, Line 43
4.8 kV CC: Pinegrove Substation Relocation and Conversion	80	Exhibit A-12, Schedule B5.4, Page 15, Line 45

Investment	Page	Capital Exhibit Reference
4.8 kV CC: Power line Conversion of MADSN 175L-W	84	Exhibit A-12, Schedule B5.4, Page 15, Line 50
4.8 kV CC: Quincy Conversion	88	Exhibit A-12, Schedule B5.4, Page 15, Line 44
4.8 kV CC: Unionville DC 301 B1 Conversion.....	92	Exhibit A-12, Schedule B5.4, Page 15, Line 56
4.8 kV CC: White Lake Decommissioning and Circuit Conversion.....	96	Exhibit A-12, Schedule B5.4, Page 16, Line 89
4.8 kV CC: Zenon Substation and Circuit Conversion	100	Exhibit A-12, Schedule B5.4, Page 16, Line 83
4.8 kV CC: SCOTN	104	Exhibit A-12, Schedule B5.4, Page 15, Line 52
8.3 kV CC: Pontiac Overhead Conversion.....	108	Exhibit A-12, Schedule B5.4, Page 16, Line 90
8.3 kV CC: Pontiac Underground Conversion	112	Exhibit A-12, Schedule B5.4, Page 16, Line 91
Ann Arbor System Improvements: Apex (Blue) Substation	116	Exhibit A-12, Schedule B5.4, Page 14, Line 3
Ann Arbor System Improvements: Argo 40 kV Reconfiguration	120	Exhibit A-12, Schedule B5.4, Page 14, Line 4
Ann Arbor System Improvements: State Substation.....	124	Exhibit A-12, Schedule B5.4, Page 14, Line 2
CODI: Alfred Substation Expansion	128	Exhibit A-12, Schedule B5.4, Page 14, Line 35
CODI: CATO Substation Expansion	132	Exhibit A-12, Schedule B5.4, Page 16, Line 79
CODI: Charlotte Network Upgrade.....	136	Exhibit A-12, Schedule B5.4, Page 14, Line 28
CODI: Corktown Substation.....	140	Exhibit A-12, Schedule B5.4, Page 14, Line 30
CODI: Garfield Network Upgrade.....	144	Exhibit A-12, Schedule B5.4, Page 16, Line 81
CODI: Garfield Radial (Midtown Circuits).....	148	Exhibit A-12, Schedule B5.4, Page 16, Line 80
CODI: Howard Conversion.....	152	Exhibit A-12, Schedule B5.4, Page 14, Line 36
CODI: Islandview Substation - Phase 1.....	156	Exhibit A-12, Schedule B5.4, Page 14, Line 31

Investment	Page	Capital Exhibit Reference
CODI: Islandview Substation - Phase 2.....	160	Exhibit A-12, Schedule B5.4, Page 14, Line 32
CODI: Islandview Substation - Phase 3.....	164	Exhibit A-12, Schedule B5.4, Page 14, Line 33
CODI: Kent/Gibson Conversion - Phase 1.....	168	Exhibit A-12, Schedule B5.4, Page 16, Line 82
CODI: Midtown Substation Expansion	172	Exhibit A-12, Schedule B5.4, Page 14, Line 34
CODI: Targeted Network Secondary Cable Replacement	176	Exhibit A-12, Schedule B5.4, Page 14, Line 29
Pilot: Primary Deconductoring.....	180	Exhibit A-12, Schedule B5.4, Page 15, Line 65
Pilot: Strategic and Service Undergrounding	184	Exhibit A-12, Schedule B5.4, Page 15, Line 64
Subtransmission Breaker Short Circuit Violations.....	188	Exhibit A-12, Schedule B5.4, Page 14, Line 22
Subtransmission Redesign & Rebuild: 40 kV Capacitor Banks at Armada and Adair.....	192	Exhibit A-12, Schedule B5.4, Page 14, Line 24
Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition.....	196	Exhibit A-12, Schedule B5.4, Page 15, Line 74
Subtransmission Redesign & Rebuild: Boyne.....	200	Exhibit A-12, Schedule B5.4, Page 14, Line 12
Subtransmission Redesign & Rebuild: Cortland Station Expansion	204	Exhibit A-12, Schedule B5.4, Page 15, Line 78
Subtransmission Redesign & Rebuild: Maxwell Amherst	208	Exhibit A-12, Schedule B5.4, Page 14, Line 6
Subtransmission Redesign & Rebuild: Praxair.....	212	Exhibit A-12, Schedule B5.4, Page 14, Line 20
Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	216	Exhibit A-12, Schedule B5.4, Page 15, Line 72
Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker.....	220	Exhibit A-12, Schedule B5.4, Page 14, Line 11
Subtransmission Redesign & Rebuild: Slocum	224	Exhibit A-12, Schedule B5.4, Page 14, Line 23
Subtransmission Redesign & Rebuild: Small Projects & Reserve.....	228	Exhibit A-12, Schedule B5.4, Page 14, Line 21
Subtransmission Redesign & Rebuild: Tie 1568.....	232	Exhibit A-12, Schedule B5.4, Page 14, Line 16

Investment	Page	Capital Exhibit Reference
Subtransmission Redesign & Rebuild: Tie 3205	236	Exhibit A-12, Schedule B5.4, Page 15, Line 71
Subtransmission Redesign & Rebuild: Tie 4104	240	Exhibit A-12, Schedule B5.4, Page 15, Line 73
Subtransmission Redesign & Rebuild: Tie 4105 Phase 1	244	Exhibit A-12, Schedule B5.4, Page 14, Line 13
Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	248	Exhibit A-12, Schedule B5.4, Page 15, Line 68
Subtransmission Redesign & Rebuild: Tie 4105 Phase 3	252	Exhibit A-12, Schedule B5.4, Page 14, Line 14
Subtransmission Redesign & Rebuild: Tie 4105 Phase 4	256	Exhibit A-12, Schedule B5.4, Page 14, Line 15
Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	260	Exhibit A-12, Schedule B5.4, Page 15, Line 69
Subtransmission Redesign & Rebuild: Tie 7504	264	Exhibit A-12, Schedule B5.4, Page 15, Line 67
Subtransmission Redesign & Rebuild: Tie 810	268	Exhibit A-12, Schedule B5.4, Page 15, Line 66
Subtransmission Redesign & Rebuild: Transformer High Side Protection Program.....	272	Exhibit A-12, Schedule B5.4, Page 14, Line 5
Subtransmission Redesign & Rebuild: Trunk 2237-ST.....	276	Exhibit A-12, Schedule B5.4, Page 14, Line 9
Subtransmission Redesign & Rebuild: Trunk 2255.....	280	Exhibit A-12, Schedule B5.4, Page 14, Line 8
Subtransmission Redesign & Rebuild: Trunk 2308.....	284	Exhibit A-12, Schedule B5.4, Page 15, Line 70
Subtransmission Redesign & Rebuild: Trunk 3509.....	288	Exhibit A-12, Schedule B5.4, Page 14, Line 18
Subtransmission Redesign & Rebuild: Trunk 4217.....	292	Exhibit A-12, Schedule B5.4, Page 14, Line 17
Subtransmission Redesign & Rebuild: Trunk 4245.....	296	Exhibit A-12, Schedule B5.4, Page 15, Line 75
Subtransmission Redesign & Rebuild: Trunk 4266.....	300	Exhibit A-12, Schedule B5.4, Page 14, Line 19
Subtransmission Redesign & Rebuild: Trunk 4911.....	304	Exhibit A-12, Schedule B5.4, Page 15, Line 76
Subtransmission Redesign & Rebuild: Trunk 7106.....	308	Exhibit A-12, Schedule B5.4, Page 14, Line 7

Investment	Page	Capital Exhibit Reference
Subtransmission Redesign & Rebuild: Trunk 7333.....	312	Exhibit A-12, Schedule B5.4, Page 14, Line 10
System Loading: Brown City.....	316	Exhibit A-12, Schedule B5.4, Page 16, Line 92
System Loading: Carleton.....	320	Exhibit A-12, Schedule B5.4, Page 15, Line 58
System Loading: Cody	324	Exhibit A-12, Schedule B5.4, Page 16, Line 95
System Loading: Diamond.....	328	Exhibit A-12, Schedule B5.4, Page 16, Line 104
System Loading: Disco.....	332	Exhibit A-12, Schedule B5.4, Page 16, Line 107
System Loading: Globe.....	336	Exhibit A-12, Schedule B5.4, Page 15, Line 63
System Loading: Goodison	340	Exhibit A-12, Schedule B5.4, Page 16, Line 102
System Loading: Grenada.....	344	Exhibit A-12, Schedule B5.4, Page 16, Line 98
System Loading: Jewell.....	348	Exhibit A-12, Schedule B5.4, Page 16, Line 100
System Loading: Kings Point.....	352	Exhibit A-12, Schedule B5.4, Page 16, Line 110
System Loading: Lark/Spruce	356	Exhibit A-12, Schedule B5.4, Page 16, Line 99
System Loading: Macomb/Golf.....	360	Exhibit A-12, Schedule B5.4, Page 16, Line 97
System Loading: Mayville.....	364	Exhibit A-12, Schedule B5.4, Page 16, Line 101
System Loading: New Baltimore/Chesterfield	368	Exhibit A-12, Schedule B5.4, Page 16, Line 109
System Loading: Otsego/Capac/Shaw	372	Exhibit A-12, Schedule B5.4, Page 16, Line 96
System Loading: Port Sanilac	376	Exhibit A-12, Schedule B5.4, Page 16, Line 93
System Loading: Richmond/Armada	381	Exhibit A-12, Schedule B5.4, Page 16, Line 94
System Loading: Spokane/Seneca.....	385	Exhibit A-12, Schedule B5.4, Page 16, Line 105

Investment	Page	Capital Exhibit Reference
System Loading: Sterling	389	Exhibit A-12, Schedule B5.4, Page 16, Line 106
System Loading: Tahoe.....	393	Exhibit A-12, Schedule B5.4, Page 16, Line 108
System Loading: Wixom	397	Exhibit A-12, Schedule B5.4, Page 16, Line 103
TCHPP Switchyard Upgrades	401	Exhibit A-12, Schedule B5.4, Page 14, Line 26

(a)

(b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)
Purpose and Necessity:	Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. Each Almont circuit is about 55 overhead line miles. Reliability: Almont substation was built in 1956 and there are no spare parts available for the breakers. Capacity: Almont 4.8 kV substation is 132% of its firm rating. ALMOT DC 304 is 93% of the day-to-day rating of 5.1MVA and ALMOT DC 303 is 87% of the day-to-day rating of 4.8MVA. Five customer requests have been received for new load on the substation but there is no capacity to serve these requests. Operability: There are little to no jumpering options available for Almont circuits because Almont is surrounded by 13.2 kV circuits and substations. In 2019, a cable failure occurred causing a breaker failure and an extensive outage for the Almont area. Due to the high loads, the substation was blocked from automatic throwover.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 41

(a)

(b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)
Scope:	• Install (1) 120 kV-13.2 kV Class R substation • Establish (4) new circuits • Reconductor (16) miles of overhead from 4.8 kV to 13.2 kV • Install (17) Isolation down transformers • Install (4) Reclosers

(a)

(b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)				
Benefits:	• Alleviates the loading issue on Almont substation, leading to: - Elimination of loading related safety risks - Improved reliability - Reduction of long duration outage risks - Reduced O&M and Capital expenses • Elimination of aging OH infrastructure, leading to: - Improved reliability- reduction in customer outage time - Reduced Capital expenses - Reduced O&M expenses • Provide additional capacity to allow for load growth • Current ALMOT 4.8 kV firm is 132%. After project completion, new MIDAS substation firm will be at 25%.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)			
Approximate Construction Schedule:	Substation Construction: 2021- 2024 Substation In Service: 2024 DC8298 Commission: 2024 DC8269 Commission: 2024 DC8715 Commission: 2024 DC8704 Commission: 2024 Decommission Almont Substation: 2025			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 30,730,922			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$3,308,607	\$5,095,409	\$734,777
	Material	\$635,595	\$904,591	\$265,223
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,944,203	\$6,000,000	\$1,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Ariel Substation and Circuit Conversion
Purpose and Necessity:	This project will complete the conversion and transfer of load from BIHAM and DUDLY circuits to a newer Ariel Substation. Drivers for the project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. Reliability: BIHAM is a one line-up switchgear substation. There is a potential of 26.8 MVA of stranded load. Operability: It neighbors a smaller, heavily loaded DUDLY substation. This project is in progress to complete the conversion and transfer load of BIHAM and DUDLY circuits to new ARIEL overhead circuits (DC 9893, DC 9815) and underground (DC 9879) ARIEL circuits. Capacity: High growth load area. Substation is at 72%
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 38

(a)

(b)

Program:	4.8 kV CC: Ariel Substation and Circuit Conversion
Scope:	- Completed overhead conversion and transfer of 3.1 MVA of load (from PL 0487 and 0141 Dudley to DC 9893 Ariel) - Completed underground conversion and transfer of 4.3 MVA of load (from DC 2734, 2720, and 1867 Birmingham to DC 9879 Ariel) - Removed of 2.4 miles of 4.8 kV cables (DC 2665 and 2734 Birmingham, DC 1669, 1650, 0487, and 0141 Dudley) - Project completion entailed construction of a modern 13.2 kV infrastructure and removal of the old 5kV class infrastructure

(a)

(b)

Program:	4.8 kV CC: Ariel Substation and Circuit Conversion				
Benefits:	- Commercial load (east of Old Woodward) continuous expansion to be reliably served by new Ariel substation - BIHAM load to be reduced from 98% to 78% firm - DUDLY 4.8 kV load to be reduced from 89% to 43% firm - This firm reduction will decrease the potential stranded load and risk of a major event at both substations - Fewer truck rolls due to elimination of aging OH infrastructure, leading to: - Improved reliability - Reduced Capital expenses - Reduced O&M expenses - Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: Ariel Substation and Circuit Conversion			
Approximate Construction Schedule:	2015 – 2022: Conceptual, Design, Execution 2023: Complete conversion			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 8,095,399			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$468,983	\$ 0	\$ 0
	Material	\$113,398	\$ 0	\$ 0
	Other	\$58,948	\$ 0	\$ 0
	Total	\$641,329	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
Purpose and Necessity:	Reliability: This project is to address the loading, aging infrastructure and substation outage risk at Birmingham substation. In addition, Quarton Rd. substation is a 1948 vintage switchgear. QTNRD circuits will be left as an island with no jumper capability after BIHAM conversion. QTNRD has significant number of customer complaints due to aging infrastructure. Capacity: The substation is operating at its substation firm rating. Any new customer load will place the substation over its firm rating. Operability: Birmingham substation, mainly serving downtown Birmingham, has a high substation outage risk. The stranded load is estimated at 21 MVA after possible load transfers and 19 MVA after mobile fleet deployments.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 86

(a)

(b)

Program:	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
Scope:	• Extend (0.1 miles) conduit. • Extend (0.4 miles) cable. • Convert area to 13.2 kV • Remove 4.8 kV pad-mount infrastructure. • Remove (1.4 miles) 4.8 kV cables.

(a)

(b)

Program:	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion				
Benefits:	• Provide sufficient capacity to serve 42.1 MVA load presently supported by aging infrastructure • Provide load relief to Birmingham, Quarton Rd, and Dudley substations • Create jumper points with new ARIEL substation and existing, LNGLK, SAVGE substations. • Reduce substation outage risk by replacing aging infrastructure				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion			
Approximate Construction Schedule:	2021 - 2022: Property acquisition inquiry and conceptual engineering. 2022-2023: Detail engineering. Start pre-conversion. 2023 - 2028: Build new substation or transfer loads to rebuild existing substations. 2029 - 2030: Construct and convert circuits. 2030: Decommission Birmingham and Quarton Road substations or establish QTNRD-BIHAM final configuration.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 53,295,645			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$630,472	\$1,287,178	\$ 0
	Material	\$275,598	\$45,822	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$906,071	\$1,333,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Buckler Circuit Conversion
Purpose and Necessity:	Argo substation was built in 1926 and is a three transformer 4.8 kV substation serving downtown Ann Arbor. Drivers for this project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits Capacity: The substation is currently unable to meet capacity needs in the rapidly growing downtown Ann Arbor area. Argo substation is at 92% of its firm rating. The loading in this area will continue to increase which will eventually overload the substation and the circuits at Argo. Buckler substation was built to support current and future loads of Argo and the surrounding substations. Operability: Increased loading on 4.8 kV circuits inhibits the ability to transfer load.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 42

(a)

(b)

Program:	4.8 kV CC: Buckler Circuit Conversion
Scope:	• Establish distribution circuit 9936 Buckler transferring a portion of distribution circuit 2942 Argo • Establish distribution circuit 9927 Buckler by converting and transferring distribution circuit 326 Argo - Install ~1600' of system cable • Convert and transfer distribution circuits 321 & 323 Argo to distribution circuit 9927 Buckler • Establish distribution circuit 9984 Buckler by converting and transferring distribution circuits 319 & 333 Argo • Establish distribution circuit 9978 Buckler by converting and transferring 334 Argo - Install ~875' of system cable • Establish Burton PL 0070 • Extend throwover circuit BCKLR DC 9999T - Install ~6000' of system cable

(a)

(b)

Program:	4.8 kV CC: Buckler Circuit Conversion				
Benefits:	• Provide sufficient capacity to serve new load growth and Economic Development • Elimination of aging OH infrastructure, leading to: - Improved reliability - Fewer truck rolls - Reduced Capital expenses - Reduced O&M expenses • Removal of aged substation equipment leading to: - Elimination of safety risks - Improved reliability - Reduction of long duration outage risks - Reduced equipment to be maintained - Reduced O&M and Capital expenses • Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Buckler Circuit Conversion			
Approximate Construction Schedule:	2022: Design and construction of preconversion areas 2023: Continue design and construction, convert approximately 2.5 miles from 4.8 kV to 13.2 kV 2024: Complete conversions of approximately 14 miles from 4.8 kV to 13.2 kV. Decommission Argo Substation			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 20,723,990			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,508,918	\$2,534,368	\$ 0
	Material	\$993,731	\$1,003,811	\$ 0
	Other	\$379,724	\$383,576	\$ 0
	Total	\$3,882,373	\$3,921,756	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Calla Circuit Conversion and Phase 2
Purpose and Necessity:	Calla substation and one distribution circuit from Calla were commissioned in 2021. This project will establish a second Calla circuit to relieve load from Diamond substation and address loading and reliability concerns on a Diamond circuit and noted below. Drivers for the project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits Reliability: Customers on a DIMND circuit regularly experience frequent and long duration outages. For this circuit, the SAIFI 5 year average is 2.25 and SAIDI 5 year average is 681. Capacity: DIMND Substation is 137% of firm rating. Operability: Customers at the end of this circuit are about ten miles from the substation and regularly experience low voltage/power quality issues. It also has limited jumpering points and capacity in the area needed to relieve load at adjacent substations.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 84

(a)

(b)

Program:	4.8 kV CC: Calla Circuit Conversion and Phase 2
Scope:	• Build 1,000ft of overhead to establish new backbone connection • Rebuild, pre-convert and convert approximately 11 miles of overhead conductor to 13.2 kV • Remove (1/2) mile of overhead infrastructure and install (3/4) mile of new overhead infrastructure in road right-of-way • Establish jumpering points and load relief to adjacent DIMND circuit

(a)

(b)

Program:	4.8 kV CC: Calla Circuit Conversion and Phase 2				
Benefits:	- Relieves load off DIMND, thus reducing percent over firm - Splits DIMND9875 which spans to just under 10 miles, thus: - Reduces overhead exposure - Improving customer power quality - Allowing for more jumpering in the area - Improving reliability - Fewer truck roles due to elimination of aging 4.8 kV OH infrastructure, leading to: - Reduced Capital expenses - Reduced O&M expenses - Improving reliability				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Calla Circuit Conversion and Phase 2			
Approximate Construction Schedule:	2023: Engineering 2024: Design and construction of backbone (currently DIMND9875) 2025: Laterals along N Territorial, and connecting portion of DIMND9866 to be rebuilt and converted			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 11,804,072			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Cortland / Oakman / Linwood Consolidation
Purpose and Necessity:	Linwood and Oakman substations, and their associated circuits, are significantly under loaded. To eliminate this underutilization, Linwood and Oakman substations will be decommissioned and their circuits will be consolidated into Cortland Substation. Cortland is a newer 120 kV fed substation and will provide a higher level of reliability. Consolidation of these substations; and subsequent removal of the associated breakers, system cable, regulators, and transformers; will eliminate the need for preventive maintenance on this equipment.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 37

(a)

(b)

Program:	4.8 kV CC: Cortland / Oakman / Linwood Consolidation
Scope:	• Consolidate Linwood & Oakman circuits into Cortland Substation • Remove twenty-seven breakers, cables and OH wire from the associated circuits, six induction regulators, and six substation transformers • Decommission Linwood and Oakman Substations

(a)

(b)

Program:	4.8 kV CC: Cortland / Oakman / Linwood Consolidation				
Benefits:	- Eliminating old cable, breakers, and transformers will: - Eliminate safety risks associated with the obsolete equipment - Reduce the overall substation outage risk - Avoid maintenance related O&M expenses - Reduce failure related O&M & Capital expenses - Transferring the load to a newer substation will: - Improve reliability - Eliminating overhead primary and secondary on circuits will: - Reduce truck rolls - Reduce O&M and Capital expenses - Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: Cortland / Oakman / Linwood Consolidation			
Approximate Construction Schedule:	2017-2018: Engineering/Design 2019-2024: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 14,107,571			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$449,266	\$1,973,798	\$ 0
	Material	\$287,820	\$562,879	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$737,086	\$2,536,677	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Crestwood Substation
Purpose and Necessity:	Other: Crestwood is an existing 120 kV-13.2 kV two transformer substation located in Dearborn, MI. The substation's property lease agreement is expiring. This request is to purchase this property from the owner instead of extending the lease for another 49 years. Purchasing the property instead of extending the lease, would save approximately \$1,000,000.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 48

(a)

(b)

Program:	4.8 kV CC: Crestwood Substation
Scope:	• Purchase the property that Crestwood substation resides on

(a)

(b)

Program:	4.8 kV CC: Crestwood Substation				
Benefits:	CREWD substation is an existing 120 kV/13.2 kV transformer, and there are no current plans to decommission it. Acquiring the property will eliminate DTE from leasing the property for another 49 years.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: Crestwood Substation			
Approximate Construction Schedule:	2022: Property Appraisal 2023: Property Purchase			
Budget Basis:	Corporate			
Total Cost: \1	The estimated project cost for this investment is \$ 665,152			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$640,259	\$ 0	\$ 0
	Total	\$640,259	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Curtis
Purpose and Necessity:	Curtis is an existing 40 kV/4.8 kV substation. Capacity and loading on Curtis and surrounding substations have created the need for a future new substation. Drivers for the project include the following: Capacity: There is limited capacity at the substation due to gradual load growth. Curtis substation is 106% of its firm rating. One circuit is 96% of its day to day rating. Two of the 40 kV trunk lines are overloaded. Operability: Due to the minimal available capacity, there is great difficulty in cascading load within the general area resulting in 42% of the areas, or 139 MVA total load, stranded after outside jumpering. Other: There is an opportunity to purchase property that will allow for the construction of a new 120/13.2 kV substation that will help address the overloading issues in the Curtis area.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 55

(a)

(b)

Program:	4.8 kV CC: Curtis
Scope:	• Purchase property to build a new Class A 120/13.2 kV Substation in the CRTIS, LAUDR and PURTN substations area

(a)

(b)

Program:	4.8 kV CC: Curtis				
Benefits:	Acquisition of this property will allow for: - The building of a new 120 kV/13.2 kV 3-transformer 2-PDC Class A substation - Increase available load capacity for the area to address the issue of overloading - Allow for the consolidation and conversion of nearby 4.8 kV LAUDR and PURTN circuits into a more reliable 13.2 kV circuits				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: Curtis			
Approximate Construction Schedule:	2024: Property Purchase and project closeout Schedule for Substation and associated load transfer work to be determine once property is purchased			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,225,178			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 17,133	\$2,174,353	\$ 0
	Total	\$ 17,133	\$2,174,353	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: GRFIN & WMSTN Conversions
Purpose and Necessity:	This project was initiated to provide load relief to Griffin (GRIFN) substation and GRIFN DC 9799. Drivers for the project include the following: • Safety: Circuits have long 4.8 kV (ungrounded) overhead miles because of the large 4.8 kV ISO down areas. Many outages occur during storms and many wires were laying on the ground from the tornado in summer 2023. • Reliability: GRFIN9799, GRFIN9883, and WMSTN9856 are some of the largest circuits and have limited jumpering points because of numerous ISO-down transformers limiting capacity and small conductor sizes on backbone limiting capacity. • Capacity: Multiple industrial customer requests have been received on GRFIN9799. • Williamston (WMSTN) substation is adjacent to GRFIN substation and is below its firm rating with capacity available. WMSTN DC 9856 also has capacity available on it. To facilitate this load transfer, 4.8 kV ISO down pockets on both circuits must be converted to 13.2 kV operation. • Operability: There are no jumpering options for either of the two circuits due to overloads and low voltage after jumpering. Jumpering points are limited because 4.8 kV ISO down pockets are limiting jumpering, these circuits are bordering Consumer’s Energy circuits, and there are small overhead line sizes for the circuits’ backbone. • Other: Industrial customer requests QPS 1 was received in 2019 and industrial customer requests QPS 2 was received in 2021. The buildings are located in an open industrial zoned area with other industrial customers nearby and more industrial customers are expected in the future.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 51

(a)

(b)

Program:	4.8 kV CC: GRFIN & WMSTN Conversions
Scope:	• Reconductor/Convert 13.6 miles of overhead among 3 distribution circuits from 4.8 kV to 13.2 kV • Remove (3) ISO down transformers • Install (3) PTSs • Install (1) Recloser • Install (3) single phase regulators • Currently, scope of work includes replacing all poles

(a)

(b)

Program:	4.8 kV CC: GRFIN & WMSTN Conversions				
Benefits:	- The conversion project is expected to bring multi-faceted benefits of safety improvements, reliability improvements, technology modernization, load relief and capacity, jumpering opportunities and cost reduction. - Elimination of aging OH infrastructure, leading to: - Improved reliability - Fewer truck rolls - Reduced Capital expenses - Reduced O&M expenses - After load transfer from GRFIN9799 to WMSTN9856: - GRFIN substation will have 2.6 MVA additional capacity 29% SAIDI improvement projection				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: GRFIN & WMSTN Conversions			
Approximate Construction Schedule:	2022: Engineering 2023: Engineering, Design, pre-conversion, and conversion construction (4.4 miles) 2024: Pre-conversion and conversion construction (4.6 miles) 2025: Pre-conversion and conversion construction (4.6 miles) Design Finish: 7/28/2025 Gate 3: 12/31/2025 Gate 4: 3/31/2026			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 14,781,161			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,663,507	\$4,747,887	\$4,618,262
	Material	\$553,998	\$1,552,113	\$1,509,738
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,217,505	\$6,300,000	\$6,128,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Hawthorne Relief and Circuit Conversion
Purpose and Necessity:	Hawthorne Substation is located in and feeds very dense areas of Dearborn Heights. To improve the substation, this project will replace the secondary bus cable from both transformers with larger cable and converting areas from 4.8kV to 13.2kV, load transfers, construction of new substations and substation expansions. Drivers for the project include the following: • Safety: ○ Replacement of the older cable makes it less vulnerable to failure and other safety issues. ○ Higher frequency of 4.8kV wire-down events (three times higher than the DTE system average) • Reliability: ○ The existing VCL type cable is recognized as a high-risk cable in the DTE system. ○ Aging 4.8kV infrastructure at neighboring substations GLEND (built in 1947), BLTMR (built in 1953), DALY (built in 1954), VILLA (built in 1961) and HAWTH (built in the 1950's). Some equipment at these substations (breakers, cables, etc.) are at an elevated risk for failure. • Capacity: ○ The substation is at 129% of firm rating, limited by secondary cables. The larger cable allows for higher ampacity ratings. ○ Two of the area substations exceed their firm ratings: VILLA (110%) and DALY (106%). ○ Five circuits exceed their day-to-day rating between GLEND, BLTMR, DALY, VILLA and HAWTH substations. There is limited load capacity to accommodate projected load growth in the area • Operability: ○ The over-firm condition limits the ability to transfer load to maintain service. ○ There are limited jumpering opportunities due to geography coupled with heavily loaded nearby circuits resulting in stranded load.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 47

(a)

(b)

Program:	4.8 kV CC: Hawthorne Relief and Circuit Conversion
Scope:	Transformer 2 Scope: • Replace Transformer #2 secondary bus cable with a new, larger cable that has a higher ampacity rating. • Replace 1200 amp disconnect at Position 'H' with 2000 amp disconnect. • Contingency plans during shut downs to perform this work. Hawthorne Conversion and Consolidation Scope: Near-Term 1: Property Procurement • Purchase properties close to HAWTH substation distribution area for a future substation Near-Term 2: Mallard DC9384 OH Work • Transfer load between circuits to help increase available load capacity in the Hawthorne area • Convert (2.5) miles overhead lines from 4.8kV to 13.2kV • Rebuilding or replacing (1000) feet of overhead conductor Near-Term 3: Mallard DC9375 OH Work • Reconductor approximately 3,270 feet backbone on MALRD 9375, 9,700 feet backbone on GLEND1974 and 6,400 feet of backbone HAWTH1392 B-Section • Convert approximately 8,090 feet of overhead lines on HAWTH1392 B-Section from 4.8 kV to 13.2 kV • Convert approximately 43,974 feet of overhead lines on GLEND1974 from 4.8 kV to 13.2 kV and transfer to MALRD9375 Near-Term 4: Hawthorne Load Transfers • Remove double built feeder for GLEND1974 along Cathedral St., up north to Orange Lawn • Re-route feeder along Beech Daly Rd, installing it in ROW to transfer load from HAWTH1392 A-Section • Use open HAWTH1392 feed to relieve loads on other overloaded Hawthorne circuits

(a)

(b)

Program:	4.8 kV CC: Hawthorne Relief and Circuit Conversion
	Near-Term 5: Property Procurement • Purchase properties along Warren Ave and E. Telegraph for future substation to consolidate GLEND and Villa circuits Long-Term 1: Mallard Substation Expansion Expand substation to accommodate 2-24/32/40 MVA transformers and 12-position PDC • Complete below grade for future third transformer, future second PDC, and two (2) replacement PDC locations Long-Term 2: Daly/Glendale & Hawthorne circuit conversion and consolidation • Convert and consolidate all DALY circuits and some GLEND circuits from 4.8 kV to 13.2 kV and transfer to expanded Mallard substation Long-Term 3: New General-Purpose Class 'A' substation along Warren Ave. • Build new Class 'A' with 3-24/32/40 MVA transformers, two (2) 12-positions PDC locations and two (2) PDC replacement locations Long-Term 4: New General-Purpose substation near Glendale and Villa substations • Develop new substation and integrate new substation and circuits near Glendale and Villa substations. Long-Term 5: Conversion of 13.2 kV Biltmore Substation • Convert 13.2 kV Class 'F' substation to temporary overhead Class 'R', then convert Class 'F' to Class 'A' substation. • Convert approximately 99,000 feet of overhead lines on BLTMR1442, BLTMR2050, and HAWTH1176 from 4.8 kV to 13.2 kV • Install approximately 7,500 feet of new cable for three (3) new distribution circuits

(a)

(b)

Program:	4.8 kV CC: Hawthorne Relief and Circuit Conversion				
Benefits:	- Replacing the transformer secondary cable and transformer secondary disconnect will increase load-carrying capability at the substation and remove N-1 overload conditions at Bus 11A & 12A - Convert dense 4.8 kV service territory to 13.2 kV. - Remove aging infrastructure and replace with new equipment leading to improved reliability and decreased truck rolls. - Install poles tall enough for clearances that will allow for conversion. - Prepare area for load transfer off of Hawthorne substation. - Expanded Mallard substation provides additional circuit capacity for area covered by the Hawthorne Initiative. - Purchasing property allows DTE to plan new substations and integrate them into the existing power grid. - Integrate NWA solutions into the power grid to assist during peak load hours. - Eliminate stranded load east of Telegraph Rd. and north of Hines Park. - New substations provide for capacity coming from the east to support the impacted area. - Investments in an EJ community				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: Hawthorne Relief and Circuit Conversion			
Approximate Construction Schedule:	2021: Engineering 2022: Design 2023: Design 2024-2026: Construction 2027: Final conversion and load transfer. Start substation construction. 2028: Complete Substation construction, Start overhead design 2029: Design and Planning 2030: Construction			
Budget Basis:	Engineering and Project Management Estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 94,029,812			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$3,135,190	\$ 0
	Material	\$ 0	\$237,971	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$3,373,161	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion
Purpose and Necessity:	Hemlock (HEMLK) is a 4.8 kV substation that is at 93% of its firm rating. The Ann Arbor area has a high percentage of electric vehicle adoption and has a goal of carbon neutrality and the elimination of natural gas heating. • Safety: Eliminating/Minimizing the utilization of double gain distribution lines and replacing aging infrastructure including equipment at an approximately 67 year old substation. • Reliability: SAIFI 5 year average is 1.35 and SAIDI 5 year average is 566. • Capacity: There is a 44% projected 15-year load growth in the area. Implementation of this project would increase the firm rating from 22.6 MVA to 35 MVA. • Operability: It also furthers the goal of moving 13.2 kV into downtown Ann Arbor. To summarize, this project will help relieve existing overload conditions at this substation and provide additional capacity for existing and new customer load.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 88

(a)

(b)

Program:	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion
Scope:	This is preliminary scope and will be refined during detailed engineering: • Replace (30) miles of overhead conductor • Pre-convert and convert 4.8kV area to 13.2kV • Decommission (1) 40-4.8kV substation and remove (1/2) mile of system cable • Install (1) new 40-13.2kV substation, install 2 miles of system conduit, and 3 miles of system cable • Commission 4 new distribution circuits and 1 throwover circuit

(a)

(b)

Program:	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion				
Benefits:	Long term goal; to decommission 4.8 kV substations and build new 13.2 kV substation in Hemlock location, bringing 13.2 kV into Ann Arbor area • Current firm is 18.8 MVA, new firm is 40.2 MVA. Capacity to increase by 117% • Provide sufficient capacity to serve growing Ann Arbor carbon neutral goals • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality for upgraded circuits by reducing circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits for both circuit tree related and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion			
Approximate Construction Schedule:	2023-2024: Engineering and Design 2024-2025: Design and Construction			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 68,192,085			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$139,109	\$684,581	\$1,277,885
	Material	\$7,487	\$38,614	\$72,080
	Other	\$5,447	\$26,804	\$50,035
	Total	\$152,402	\$750,000	\$1,400,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Hilton Substation and Circuit Conversion
Purpose and Necessity:	The Hilton Road (HLTRD) Phase 2 Initiative is part of the Royal Oak Area plan, which was implemented to align strategies between serving new load and addressing aging infrastructure. The HLTRD Phase 2 Initiative will increase operability, capacity, and reliability for commercial and residential customers in the Ferndale and Oak Park area. There are several drivers for this initiative including: • Safety: The wire-down events for the substations in this area over the last five years ranges between 57-118. Wind and Trees are the most frequent cause of outages. • Reliability: The subtransmission sustained outages at LINC� station due to cable failure accounted for approximately 60% of the outages. The substation equipment risk in this area is higher than the DTE System average. The average reliability for the substations in this area is lower than the DTE System average. • Capacity: Ferndale and Oak Park area have about 52 MVA of load that is covered by (21) circuits with average load per circuit is 2.5 MVA at 4.8 kV. • Operability: The current configuration has a potential for stranded load and long restoration times for customers in the event of an outage. • Other: This project will decommission 24 kV trunk lines at LINC� (Lincoln) station with average weighted cable age is ~55 years. It will also decommission LINC� station and allow the property to be utilized for the future LINC� substation conversion.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 54

(a)

(b)

Program:	4.8 kV CC: Hilton Substation and Circuit Conversion
Scope:	• Expand Hilton Road Substation so that it has 3 transformers and 2 PDCs • Convert 100% of circuits from FERND, HAZPK, and WDSID substations and transfer to Hilton Road Substation • Decommission FERND, HAZPK, and WDSID substations

(a)

(b)

Program:	4.8 kV CC: Hilton Substation and Circuit Conversion				
Benefits:	• Significant reduction in circuit wire down events • 13.2 kV Y- Circuit wire downs pose less danger compared to existing 4.8 Delta Circuits • Reduce equipment failures • Provide capacity to new businesses in downtown Royal Oak • Significantly increase capacity of Hilton Road substation to accommodate load growth (Capacity increase of ~50%) • Reduction in circuit customer interruptions with increased protection • Reduce substation outage risk by replacing aging infrastructure with more robust 13.2 kV system • Reduce time & cost to serve new customers with easier planned shutdowns and more available loop schemes • Significantly reduce the amount of stranded load in the area providing more reliable power to our customers.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x		x

(a)

(b)

Program:	4.8 kV CC: Hilton Substation and Circuit Conversion			
Approximate Construction Schedule:	2023: Engineer and design overhead conversion 2024: Design overhead conversion 2025: Design Hilton Road substation expansion, Overhead conversion construction 2026: Finish Design Hilton Road substation expansion / Start Construction, Overhead conversion construction, Engineer and design overhead conversion 2027: Complete Construction of Hilton Road substation expansion, Overhead conversion construction 2028: Overhead conversion construction 2029: Overhead conversion construction, Engineer and design decommission FERND sub and LINCN Trunk lines, Engineer and design overhead conversion			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 286,168,275			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$651,654	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$651,654	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade
Purpose and Necessity:	• Safety: Significant assets are at high risk level including transformers, regulators, oil circuit breakers and disconnects. Along with 4.8 kV and 24 kV underground cable. • Reliability: This area experiences wire down events which exceed the system average. • Capacity: The Detroit Economic Growth Corporation has assembled the I-94 Industrial Park site – a 186-acre site north of I-94 between Mt. Elliott and Van Dyke on Detroit’s east side. It is part of the 3,203-acre Mt. Elliot Development Zone, which is the single largest industrial district in Detroit and encompasses automotive, metal, transportation and logistics clusters. It offers access to major transportation assets. The site is a federally designated Historically Underutilized Business Zone and a state designated Renaissance Zone. Recent new loads were fed from the aging Lynch and Lambert 4.8 kV substations. The new substation is required to serve the load growth in and around I-94 industrial park and allows for decommissioning of the aging Lynch, Lambert, and Pulford 4.8 kV substations. • Operability: Future Promenade circuits will have loop schemes and jumpering points.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 40

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade
Scope:	• Installing (1) 120-13.2 kV substation above grade from project one. • Installing (2) transformers • Installing (1) circuit switcher • Installing (2) capacitor banks • Installing (.3) miles of cable inside substation • Installing terminations

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade				
Benefits:	• 120-13.2 kV Class 'A' substation fully constructed and ready to carry load for the local distribution area • Long-lead materials are ordered in time to construct substation • A significant cost-savings is gained from the solution developed by DTE and ITC in Project 1 are implemented in Project 2 • Contingency violations on the 120 kV system are resolved by implementing the design developed in Project 1				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade			
Approximate Construction Schedule:	2021: Engineering and Approvals, Detailed Design 2022: Detailed Design, Procure Long-Lead substation equipment 2023: Procure long-lead equipment 2024: Procure long-lead equipment, construct substation 2025: Closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 7,558,170			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,856,642	\$1,310,930	\$ 0
	Material	\$1,347,847	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$4,204,489	\$1,310,930	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade
Purpose and Necessity:	• Safety: Significant assets are at high risk level including transformers, regulators, oil circuit breakers and disconnects. Along with 4.8 kV and 24 kV underground cable. • Reliability: This area experiences wire down events which exceed the system average. • Capacity: The Detroit Economic Growth Corporation has assembled the I-94 Industrial Park site – a 186-acre site north of I-94 between Mt. Elliott and Van Dyke on Detroit’s east side. It is part of the 3,203-acre Mt. Elliot Development Zone, which is the single largest industrial district in Detroit and encompasses automotive, metal, transportation and logistics clusters. It offers access to major transportation assets. The site is a federally designated Historically Underutilized Business Zone and a state designated Renaissance Zone. Recent new loads were fed from the aging Lynch and Lambert 4.8 kV substations. The new substation is required to serve the load growth in and around I-94 industrial park and allows for decommissioning of the aging Lynch, Lambert, and Pulford 4.8 kV substations. • Operability: Future Promenade circuits will have loop schemes and jumpering points.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 39

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade
Scope:	Installing (1) 120-13.2 kV substation below grade work.

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade				
Benefits:	• Execution of this project will ensure that IVIEW is built on schedule • Below grade construction aligns with future projects within the Promenade Initiative • ITC will build equipment on Promenade site, will complete their cable project, and will provide 120 kV to IVIEW • Substation design for Promenade substation will be complete • Above grade construction can be completed when ready • Provisions for 3 substation transformers, 4 PDCs, and 6 station capacitors are accounted for in the project				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade			
Approximate Construction Schedule:	2016-2018: Property Procurement Jan. 2021 - May 2021: Engineering and Approvals May 2021 - Dec. 2021: Detailed Design 2022: Construct Promenade Below Grade, Construct Exit Conduit 2023: Closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 15,574,645			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,985,797	\$ 0	\$ 0
	Material	\$187,750	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,173,547	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: ISO Conversion Program
Purpose and Necessity:	The Company operates some circuits as ISO downs, 4.8 kV circuits (or portions of circuits) that are fed from a 13.2 kV substation. On these circuits, the higher voltage is stepped down to 4.8 kV by a transformer and the rest of the circuit downstream of that transformer operates at 4.8 kV. The portion of the circuit operating at 4.8V in an ISO down area has the same characteristics of a 4.8 kV circuit fed from a 4.8 kV substation including reliability, capacity, safety and operational flexibility challenges. 4.8 kV ISO down circuits are already fed from a 13.2 kV substation which removes the substation firm rating and the substation risk ranking from prioritization consideration. Additionally, a new substation source is not needed to complete conversion. Without the need to consider substation factors, safety (wire down reduction), reliability (customer minute interruptions), and costs (avoided O&M and capital) become the driving factors for prioritization of 4.8 kV ISO down circuits.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 87

(a)

(b)

Program:	4.8 kV CC: ISO Conversion Program
Scope:	• Installing controls and automation on the circuits • Completing overhead conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire. • Rebuilding underground infrastructure • Reconductoring overhead lines as needed • Reconfiguring circuits and establishing new jumpering points • Removing ISO down transformers • Rebuilding underground infrastructure as needed

(a)

(b)

Program:	4.8 kV CC: ISO Conversion Program				
Benefits:	- The 4.8 kV ISO down conversion projects are expected to bring multi-faceted benefits of safety improvements, reliability improvements, technology modernization, potential circuit load relief and cost reduction. - Elimination of aging OH infrastructure, leading to: - Improved reliability - Fewer truck rolls - Reduced Capital expenses - Reduced O&M expenses - Invest in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x		x	x

(a)

(b)

Program:	4.8 kV CC: ISO Conversion Program			
Approximate Construction Schedule:	2022: Engineering for Camden and Gilbert circuit areas 2023: Design and start Construction of Camden and Gilbert ISO areas 2024 & beyond: Engineer & Design for the following year's plan, construct the current year's plan			
Budget Basis:	Funding levels targeted to achieve mile targets of the program			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$5,182,649	\$1,700,000	\$ 0
	Material	\$1,283,526	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$6,466,175	\$1,700,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
Purpose and Necessity:	Elba is 40-4.8 kV substation. Lapeer has a 40-4.8 kV substation and a 120-13.2 kV substation. This project will build a new 120-13.2 kV substation named Apollo and decommission Elba and Lapeer 4.8 kV substations. Drivers for this project include the following: • Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits • Reliability: Lapeer and Elba substations have aging infrastructure and islanded 4.8 kV systems. Elba has problematic subtransmission infrastructure that has a history of poor reliability performance and limits shutdown capability for operation and maintenance. The Lapeer-Elba area has also experienced low voltage and power quality issues. • Capacity: Lapeer substation has a 13.2 kV substation and a 4.8 kV substation. The 13.2 kV substation is at 107% of its firm rating. One circuit is at its day-to-day rating with another one approaching its day-to-day rating. Elba substation is a two circuit 4.8 kV substation. It is 125% of its firm rating and the substation transformer exceeds its day-to-day rating. One circuit exceeds its day-to-day rating. General load growth has been strong in the area (6-8% in 2017 and 2018). • Operability: Limited jumpering options are available at Elba substation since it is an islanded 4.8 kV substation.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 85

(a)

(b)

Program:	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
Scope:	• Install (1) new substation • Convert (9) miles of existing overhead conductor • Reconductor (4) miles of existing overhead conductor • Decommission (6.2) miles of 40 kV sub-transmission • Decommission (1) existing substation

(a)

(b)

Program:	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)				
Benefits:	• Alleviates the loading issue on Lapeer and Elba substations, leading to: ○ Elimination of loading related risks ○ Improved reliability ○ Reduction of long duration outage risks ○ Reduced O&M and Capital expenses • Elimination of aging OH infrastructure, leading to: ○ Improved reliability ○ Fewer truck rolls ○ Reduced Capital expenses ○ Reduced O&M expenses • Reduce new customer connection timeframe and cost • Increased jumpering between circuits due to all circuits being the same operating voltage				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)			
Approximate Construction Schedule:	2020: Engineering 2021: Design for Substation and Circuits 2022: Substation Construction 2023: Construction of APOLO Circuit 1 and 2 2024: Decommissioning ELBA sub, decommissioning and removal of Elba Tap Tie 9111, construction of APOLO Circuit 3-5, and transfer to LAPER 4.8 kV Circuits 2025: Decommissioning LAPER 4.8 kV and close out			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 69,402,541			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,295,697	\$1,461,653	\$12,000,000
	Material	\$-349,036	\$2,096,356	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$946,661	\$3,558,009	\$12,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion
Purpose and Necessity:	DC 8241 MAUME has experienced reliability issues and has received numerous customer complaints resulting in town hall and customer meetings.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 49

(a)

(b)

Program:	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion
Scope:	• Pre-convert 15,200ft of OH, which includes reconductoring, replacing all poles, building to 13.2 kV spec and replacing any straight voltage transformer • A total of 56 OH transformers would be converted from 4.8 kV to 13.2 kV

(a)

(b)

Program:	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion				
Benefits:	• Completion of this work would eliminate all 4.8 kV in the Downtown Clawson area. • Improved reliability, reduced risk of customer equipment damage and customer complaints.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x		x	x

(a)

(b)

Program:	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion			
Approximate Construction Schedule:	2021: Engineering 2022: Design, pre-conversion, and conversion construction 2023: Close-out			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,627,140			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 12,965	\$ 0	\$ 0
	Material	\$ 9,935	\$ 0	\$ 0
	Other	\$ 1,613	\$ 0	\$ 0
	Total	\$ 24,513	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: McKinstry Sub Decommission
Purpose and Necessity:	McKinstry is a 24 kV/4.8 kV Class C substation. As part of the Gordie Howe Bridge Project, all of its circuits have been consolidated, converted and transferred to Zenon 120 kV/13.2 kV Class A substation. This specific project is to decommission McKinstry Substation, demolish the substation building and remove all associated equipment. Drivers for this project include the following: • Capacity: There is no load on the MCKNY substation as all load has been transferred to nearby substations. • Other: This project will decommission three 24 kV trunk lines. It will also decommission McKinstry Substation and demolish the substation building.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 43

(a)

(b)

Program:	4.8 kV CC: McKinstry Sub Decommission
Scope:	Decommission McKinstry substation and remove all associated equipment including: • Removing three transformers • Removing 22 breakers • Decommissioning three trunk lines

(a)

(b)

Program:	4.8 kV CC: McKinstry Sub Decommission				
Benefits:	• Eliminate aging infrastructure substation • This completes phase two of three of the Zenon Substation construction project				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: McKinstry Sub Decommission			
Approximate Construction Schedule:	2022: Complete design 2023-2024: Complete decommission and removal			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,001,399			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$558,800	\$3,376,288	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$558,800	\$3,376,288	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Pinegrove Substation Relocation and Conversion
Purpose and Necessity:	This project is driven by MDOT needing the substation to be moved. Secondary drivers include substation risk and reliability. The Bluewater Bridge is being expanded and Pinegrove substation will need to be removed to accommodate the expansion. New Neon substation will need two 40 KV feeds (Pine Grove was fed by one 40 KV and two 24 KV feeds). TRUNK 6841 will be feeding TRF 1 Neon. New TRUNK 847 40 kV will be feeding TRF 2 Neon. New TRUNK 847 will be established on BUNCE Bus 2 40 kV. Equipment at BUNCE POS 'SN' will be decommissioned and new 40 kV equipment will be installed. Pinegrove substation interferes with MDOT's expansion plans. Pinegrove substation is also a 100 year old sub and is not a standard configuration. Pine Grove has no circuit switcher on high side of the transformer, instead it has high speed ground switches. The substation is fed 24 kV with 4.8 kV distribution. This relocation work will decommission the current sub and build a new substation to current standards out of the way of MDOT's expansion plans.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 45

(a)

(b)

Program:	4.8 kV CC: Pinegrove Substation Relocation and Conversion
Scope:	Project 1 - Build new NEON Substation 40 kV fed, two (2) 15/20/25 MVA transformers, nine (9) position 13.2 kV Class A substation, located West of 10th Ave. between Church and Elmwood in Port Huron, MI 48060. Project does NOT include system conduit, cable and overhead circuit connections downstream of the line breakers. Project will stub out conduit 5 feet outside substation fence. Project 2 - Bunce and new OH Subtrans - Install new HS 53 at POS SR - Remove and decommission TRF2 40-13.2 KV, HS1-2 and HS2-2, Cable terminations for BUNCE PL8784, 1919 feet of 1-0 AWG cable 13.2 KV PL8784. - Install new 40 kV breaker, associated 1200 AMPS disconnects, relay panel, position cable terminations. - New TRUNK 847: Install new Conduit 2550 feet. - New TRUNK 847: Install 800 feet of 350 EPR and 2680 feet of 650 EPR new 40 KV cable from New POS SN Bunce to CP2 in a new conduit, replace CP2. - Transfer TRUNK 830 OHL to new TRUNK 847, replace one pole that is built to 24 KV. - Contingency plan will be needed

(a)

(b)

Program:	4.8 kV CC: Pinegrove Substation Relocation and Conversion				
Benefits:	• Improved and additional capacity • Creates capacity to improve load growth • Replaced aging infrastructure to improve substation operability and reliability • Creates circuit jumpering options to utilize for planned construction or outage restoration				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Pinegrove Substation Relocation and Conversion			
Approximate Construction Schedule:	Schedule Dictated by MDOT Needs 2022: Engineering, Design, NEON Substation Design, NEON Substation Construction begins, Conduit Construction begins. 2023: NEON Substation Construction continues, Conduit Construction finish, Cable construction, OH Pre-Conversion 2024: NEON Substation Construction complete and energized, OH Conversion, decommissioning of Pine Grove Substation 2025: OH Pre-conversion and conversion as indicated by scope in Project 7			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 80,881,749			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$5,541,079	\$36,395,854	\$ 0
	Material	\$14,498,965	\$10,796,997	\$ 0
	Other	\$681,310	\$4,032,999	\$4,593,777
	Subtotal	\$20,721,354	\$51,225,850	\$4,593,777
	CIAC		\$-17,000,000	\$-17,000,000
	Total	\$20,721,354	\$34,225,850	\$-12,406,223

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Power line Conversion of MADSN 175L-W
Purpose and Necessity:	Work is necessary to convert Madison Loop Power Line (LPL) 175 to two distinct Power Lines (PL) and remove pilot wire circuit due to cable failure. Pilot wire circuit isunjacketed, leaded cable. Numerous attempts to repair the circuit have been unsuccessful; cable continues to fail hi-potential test.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 50

(a)

(b)

Program:	4.8 kV CC: Power line Conversion of MADSN 175L-W
Scope:	• Retag LPL 175L to PL 703 and retag pilot wire to "Dead" from Madison Substation to building • Retag LPL 175W to PL 250 and retag pilot wire to "Dead" from Madison Substation to building • Clean 54 manholes and remove ~8,716 ft of pilot wire cable.

(a)

(b)

Program:	4.8 kV CC: Power line Conversion of MADSN 175L-W				
Benefits:	Eliminates pilot wire cable failure.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	

(a)

(b)

Program:	4.8 kV CC: Power line Conversion of MADSN 175L-W			
Approximate Construction Schedule:	2022: Engineering and design, begin construction 2023: Complete construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 685,201			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$485,095	\$ 0	\$ 0
	Material	\$33,770	\$ 0	\$ 0
	Other	\$59,020	\$ 0	\$ 0
	Total	\$577,885	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Quincy Conversion
Purpose and Necessity:	Quincy substation is a single transformer, single circuit 4.8 kV substation. This project will construct a new 13.2 kV Subtransmission Distribution Facility (STDF) and decommission the aging Quincy substation. Drivers for the project include the following: • Safety: Power transformer sits on railroad ties instead of a transformer pad. Overhead stress from the leaning transformer causes safety concerns for those working on site. • Other: QUNCY substation has low oil levels due to oil leaks, potentially causing future environmental impacts. QUNCY transformer is constructed on railroad ties that are rotten, causing the transformer to lean, adding stress to the overhead equipment.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 44

(a)

(b)

Program:	4.8 kV CC: Quincy Conversion
Scope:	• Install (1) new pad mount STDF at Quincy Property • Replace (20) overhead transformers • Reconductor (2) miles of overhead conductor • Install (3) mile of new overhead neutral conductor • Install (8) ISO-Down transformers • Decommission (1) QUNCY substation

(a)

(b)

Program:	4.8 kV CC: Quincy Conversion				
Benefits:	• Replace damage/high risk equipment • Setup to relieve Lexington substations which are 158% (13.2 kV) and 81% (4.8 kV) of firm, or Worth that is at 105% and possibly Lake Port substation at 103% • Replace leaking transformer with new transformer • Eliminate environmental risk				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Quincy Conversion			
Approximate Construction Schedule:	2022: Engineering 2023-2024: Design & Construction - O/H reconductoring and pre-conversion, STDF Construction & 3 miles Conversion			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 5,403,456			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,584,819	\$1,632,606	\$ 0
	Material	\$ 82,507	\$ 59,716	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,667,327	\$1,692,322	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Unionville DC 301 B1 Conversion
Purpose and Necessity:	This project will convert a section of a circuit to 13.2 kV operation and reduce flicker from motor starts. Drivers for the project include the following: Reliability: Two residential customers filed MPSC complaints in January 2023. These customers are seeing a larger voltage flicker driven primarily by the operation of a residential on-demand water heater. However, the area has a history of motor start issues. The area is predominately agricultural. All sites have motors that operate within limits but collectively operate outside of limits. The issues will persist and complaints will continue until work is done to improve the circuit performance.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 56

(a)

(b)

Program:	4.8 kV CC: Unionville DC 301 B1 Conversion
Scope:	Convert the B1 fuse area by: • Installing 3-500 kVA ISO up transformers • Install ~32,000 ft of secondary neutral • Remove three sets of regulators • Install a new set of 76 kVA regulators • Relocate the 300 kVAR capacitor on the circuit

(a)

(b)

Program:	4.8 kV CC: Unionville DC 301 B1 Conversion				
Benefits:	Increased motor start capabilities in the area that will reduce the size of the flicker				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Unionville DC 301 B1 Conversion			
Approximate Construction Schedule:	2023: Conceptual engineering, Engineering and design 2024: Design and Construction			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 2,953,167			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$2,376,478	\$ 0
	Material	\$ 0	\$534,522	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$2,911,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: White Lake Decommissioning and Circuit Conversion
Purpose and Necessity:	This project will build a new 13.2 kV substation and decommission an aging 4.8 kV substation. Drivers for the project include the following: • Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. • Reliability: White Lake (WHTLK) substation is an older substation with multiple at-risk equipment that need to be upgraded or replaced. There is also a 40 kV capacitor (CAP1-1) that has multiple at-risk equipment in need of upgrade or replacement. The existing substation site is too small to support replacing major equipment. • Capacity: WHTLK has a 4.8 kV substation and a 13.2 kV substation. Each one has a single transformer and a single circuit. The 13.2 kV substation is 88% of its firm rating. The 4.8 kV substation is 100% of its firm rating. The circuit is at 100% of its day to day rating. • Operability: White Lake circuits cannot be jumpered to one another because of the two operating voltages at the substation (4.8 and 13.2 kV)
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 89

(a)

(b)

Program:	4.8 kV CC: White Lake Decommissioning and Circuit Conversion
Scope:	• Acquiring property (Purchased property in 2019) • Installing (1) 40-13.2 kV substation • Installing (2) miles of system conduit • Installing (4) miles of system cable • Convert area to 13.2 kV • Decommission (1) 40-4.8 kV substation

(a)

(b)

Program:	4.8 kV CC: White Lake Decommissioning and Circuit Conversion				
Benefits:	• Reduce equipment risk by providing load relief • Provide sufficient capacity to serve existing and new customers • Create circuit jumpering point to improve operability • Elimination of aging OH infrastructure, leading to: - Improved reliability - Fewer truck rolls - Reduced capital expenses - Reduced O&M expenses • Removal of antiquated and failing substation equipment leading to: - Elimination of safety risks - Improved reliability - Reduction of long duration outage risks - Reduced equipment to be maintained • Reduced O&M and Capital expenses				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	4.8 kV CC: White Lake Decommissioning and Circuit Conversion			
Approximate Construction Schedule:	2019: Close on Property 2024: Engineering 2025: Substation Design (Develop all site plans for community approvals, construction permits and construction) 2026: Fence for property, order large equipment, pre-conversion design of 4.8 kV circuit area, construction of substation to begin 2027: Substation construction, pre-conversion construction, 13.2 kV circuit configuration/reliability upgrades (loop schemes, PTS, sectionalizing) 2028: Convert 4.8 kV circuit area and cutover to new substation, establish final circuit configuration for two 13.2 kV circuits, decommission existing White Lk Substations - 4.8 kV and 13.2 kV class 'T' facilities			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 40,436,842			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: Zenon Substation and Circuit Conversion
Purpose and Necessity:	Zenon Class A substation was constructed in 2012 with dual winding secondary voltage (4.8/13.2 kV) transformers as a means to quickly transfer 4.8 kV load from McKinstry substation while facilitating future 13.2 kV conversion. Zenon Phase 1 was driven by the construction of the Gordie Howe International Bridge (GHIB) crossing, and the McKinstry substation conflicts with the project. Four 13.2 kV circuits were commissioned to either remove, consolidate, and/or convert portions of McKinstry & West End in direct conflict with the bridge plaza and the remaining McKinstry circuits were transferred to the 4.8 kV side of Zenon. Due to the 2021 flooding events in the Scotten substation area, low reliability, high propensity of wiredowns on the 4.8 kV system in the area, and load increases driven by West Riverfront and Corktown development, the second phase of Zenon Conversions is to be initiated. The scope within this project was submitted for Round 1 of GRIP/IIJA grants in 2023. The Company was not awarded a grant in Round 1 and is submitting a modified application in Round 2 in 2024. If the Company is awarded a grant in Round 2, the timing of the project will be accelerated. • Reliability: Recent flooding events in the Scotten substation area, low reliability, high propensity of wiredowns on the 4.8 kV system in the area • Capacity: Load increases driven by West Riverfront and Corktown developments • Operability: Completing this work will decommission WSEND and SCOTN substation along with their associated 24 kV trunk lines
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 83

(a)

(b)

Program:	4.8 kV CC: Zenon Substation and Circuit Conversion
Scope:	• Establish (7) new ZENON 13.2 kV circuits from existing 13.2 kV power delivery center and convert 4.8 kV power deliver center at ZENON and/or CORKT • Pre-convert & convert 144 miles of 4.8 kV overhead to 13.2 kV • Install 3 miles of conduit • Install 17 miles of system cable • Convert or Iso-down (70) primary service customers • Replace two transformers at ZENON substation • Install a third 24/32/40 MVA transformer at ZENON substation • Install third transformer, second PDC, and third cap bank at Corktown substation • Decommission SCOTN substation and 24 kV trunk lines • Decommission WSEND substation and 24 kV trunk lines

(a)

(b)

Program:	4.8 kV CC: Zenon Substation and Circuit Conversion				
Benefits:	• Significant reduction in circuit wire down events • 13.2 kV Y- Circuit wire downs pose less danger compared to existing 4.8 Delta Circuits • Reduce equipment failures • Provide capacity to new businesses on West Riverfront of Detroit • Significantly increase capacity of surrounding substations to accommodate load growth 15 years+ • Reduction in circuit customer interruptions with increased protection • Reduce substation outage risk by replacing aging infrastructure with more robust 13.2 kV system • Reduce time & cost to serve new customers with easier planned shutdowns and more available loop schemes • Significantly reduce the amount of stranded load in the area providing more reliable power to our customers. • Eliminate future flood risk to SCOTN circuits (5000 customers)				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	4.8 kV CC: Zenon Substation and Circuit Conversion			
Approximate Construction Schedule:	2024: Detailed Engineering 2025: Detailed Design 2025-2027-Substation Expansion, OH Preconversion & System Conduit & Cable 2028: OH Conversions 2027-2028: Scotten & West End substation & 24 kV decommissioning			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 155,800,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	4.8 kV CC: SCOTN
Purpose and Necessity:	In June 2021, flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers. After further investigation, it was concluded that all (36) position breakers will need to be replaced. The intent of this project is to minimize the number of breakers to be replaced by consolidating lightly loaded circuits and to put the substation back to normal configuration.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 52

(a)

(b)

Program:	4.8 kV CC: SCOTN
Scope:	• Decommission 2700' OH Feeder • Decommission 14000' system cable • Decommission and remove (4) breakers • Remove (6) fuses • Remove (4) disconnects • Remove (1) recloser • Install (2) reclosers • Remove (5,810ft) OH Conductor • Install (1) switch • Install 100' cable

(a)

(b)

Program:	4.8 kV CC: SCOTN				
Benefits:	- Remove (3) circuits from SCOTN substation allowing for position consolidation - Establish new/additional jumpering points to improve operability - Reduce Substation O&M costs - Zenon and Corktown sub conversion project will facilitate for future 13.2 kV conversion of SCOTN sub, although no conversion project is currently planned, some portions of OH will be pre-converted on SCOTN during this work				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	4.8 kV CC: SCOTN			
Approximate Construction Schedule:	2022: Engineering/Design 2023-2024: Construction			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 2,975,622			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,043,956	\$1,855,092	\$ 0
	Material	\$130,499	\$ 29,788	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,174,455	\$1,884,880	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	8.3 kV CC: Pontiac Overhead Conversion
Purpose and Necessity:	Drivers for this project include the following: • Safety: 8.3kV causes a higher safety risk in the event of a failure due to aging and obsolete equipment • Operability: Because the 8.3 kV system is an island surrounded by the 13.2 kV system, it is impossible to transfer load from 8.3 kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3 kV substation outage event. • Reliability: In addition, replacement parts are no longer available for 8.3 kV breakers, other substation equipment and equipment in the underground vaults due to their obsolescence. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3 kV equipment fails. Crews must be trained to operate and maintain the 8.3 kV system, adding to training, operation and maintenance costs. • Capacity: Meanwhile, the City of Pontiac is experiencing an economic rebound, with an estimated 40 MVA (37 percent) load growth in the next five to ten years.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 90

(a)

(b)

Program:	8.3 kV CC: Pontiac Overhead Conversion
Scope:	• Purchase property • Extend (1.4 miles) conduit • Extend (14 miles) cable • Replace (33.4 miles) overhead • Build new 120-13.2 kV substation • Convert (33.4 miles) to 13.2 kV • Decommission five substations

(a)

(b)

Program:	8.3 kV CC: Pontiac Overhead Conversion				
Benefits:	• Provide sufficient capacity to serve growing areas • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability, and power quality for upgraded circuits by reducing 85% of circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits by 85% for both circuit tree related, and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automaton, including DER integration • Reduce new customer connection timeframe and cost • Corrects front line employees' exposure to unsafe work environments • Distribution System capacity increase: 64%				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	8.3 kV CC: Pontiac Overhead Conversion			
Approximate Construction Schedule:	2022-2024: Conceptual, Purchase property, substation design 2025-2027: Design, Substation construction, Conduit construction UG extension, 2027-2030: OH Pre-conversion, Conversion, decommissioning			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 157,147,746			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$8,982,855	\$15,899,991	\$18,205,972
	Material	\$946,372	\$3,276,962	\$ 100,328
	Other	\$ 0	\$ 0	\$ 0
	Total	\$9,929,227	\$19,176,953	\$18,306,300

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	8.3 kV CC: Pontiac Underground Conversion
Purpose and Necessity:	Drivers for the Pontiac Underground Conversion project include the following: • Safety: The aging 8.3 kV system is Pontiac is obsolete and poses a safety hazard for any repairs needed to be made. • Reliability: Because the 8.3 kV system is an island surrounded by the 13.2 kV system, it is impossible to transfer load from 8.3 kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3 kV substation outage event. • Operability: The 8.32kV system serves 29.5 MVA of load and over 7,000 customers. The largest services are delivered through 8.3 kV rated underground equipment. These services contain customer-owned switchgear, fuses, and transformers. Replacement of the 8.3 kV substations with 13.2 kV infrastructure requires the replacement of these services with 15kV rated equipment to enable better operability.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 91

(a)

(b)

Program:	8.3 kV CC: Pontiac Underground Conversion
Scope:	Pre-convert area to 13.2 kV: • Pre-convert current 8.3 kV system to enable deployment of scheduled 13.2 kV substation expansion • In preparation for 8.3 kV substations upgrade to 13.2 kV substations, create ability to support 15KV class services • Establish strong working relationships with affected businesses and City officials to secure optimal services & infrastructure replacement cadence Equipment will be removed and replaced based on field inspections and may include some or all of the following: • Replace customer equipment: 4 switchgears, 2 metal clad switchgear, 4 fuse positions • Replace customer transformers: twenty-eight single-phase, ten three-phase, fourteen special order (>750KVA) transformers • Replace eighteen customer cables (estimated 800 feet per site) rated less than 15KV class • Coordinate efforts to deploy DGs (2 weeks minimum) to support conversion and transfer at Redundant Services - Critical Customer facilities

(a)

(b)

Program:	8.3 kV CC: Pontiac Underground Conversion				
Benefits:	- Replacement of non-compatible, outdated, non-repairable, non-standard voltage class infrastructure, leading to: - Elimination of safety risks - Improved reliability - Reduction of long duration outage risks - Reduced equipment to be maintained & stocked - Reduced O&M and Capital expenses - Increased jumpering between circuits due to all circuits being the same operating voltage - Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	8.3 kV CC: Pontiac Underground Conversion			
Approximate Construction Schedule:	2020-2021: Conceptual engineering 2021-2023: Detail Design 2023: Purchase equipment and prep work 2023 – 2026: Equipment, TRFs, cable replacements, conversion			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 17,408,720			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,124,152	\$3,152,456	\$3,693,669
	Material	\$72,743	\$97,143	\$193,331
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,196,895	\$3,249,599	\$3,887,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Ann Arbor System Improvements: Apex (Blue) Substation
Purpose and Necessity:	This project, coupled with the other Ann Arbor System Improvements Projects will address the following issues: • Reliability: The existing distribution system in the Greater Ann Arbor area experience's frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers. • Capacity: The subtransmission system in Ann Arbor is not adequately sized to accommodate existing load and accelerated load growth in the area. The overloaded system is an impediment to economic growth. • Operability: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 3

(a)

(b)

Program:	Ann Arbor System Improvements: Apex (Blue) Substation
Scope:	• ITC to design and construct five miles of 120 kV line to Apex Station. • Construct a new 120/40 kV class 'D' station (including two 60/80/100 MVA, 120-40 kV transformers and 11 Subtransmission breakers). • Reconfigure the existing 40 kV system in the area. Establish eight Subtransmission circuits out of Apex station. Load from three existing stations will be transferred to Apex Station. Substations impacted include: University, Ingalls, Academy, Campus, Leland, and Bates

(a)

(b)

Program:	Ann Arbor System Improvements: Apex (Blue) Substation				
Benefits:	• Provide sufficient capacity to serve existing and new customer load. • Reduce equipment risk by providing load relief to Subtransmission system in the Greater Ann Arbor area • Improve system shutdown capability and operability. • Improve customer reliability and power quality.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Ann Arbor System Improvements: Apex (Blue) Substation			
Approximate Construction Schedule:	Project complete in 2023			
Budget Basis:	Project Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 20,341,255			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,107,216	\$ 0	\$ 0
	Material	\$ 77,327	\$ 0	\$ 0
	Other	\$293,382	\$ 0	\$ 0
	Total	\$1,477,925	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Ann Arbor System Improvements: Argo 40 kV Reconfiguration
Purpose and Necessity:	- Capacity: Due to high growth in Ann Arbor, ARGO substation does not have capacity to serve downtown Ann Arbor. This is part of the ARGO decommissioning project and will remove Argo from service (see related project 4.8 kV CC: Buckler Circuit Conversion). - Other: This project avoids \$5M of work required at the ARGO should the reconfiguration not take place.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 4

(a)

(b)

Program:	Ann Arbor System Improvements: Argo 40 kV Reconfiguration
Scope:	• Remove 3 buses • Remove 10 breakers • Remove 18 disconnects • Remove all relay panels and controls

(a)

(b)

Program:	Ann Arbor System Improvements: Argo 40 kV Reconfiguration				
Benefits:	• Provide sufficient capacity to serve existing and new customer load • Reduce equipment risk by providing load relief to subtransmission system in the Greater Ann Arbor area • Improve system shutdown capability and operability • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Ann Arbor System Improvements: Argo 40 kV Reconfiguration			
Approximate Construction Schedule:	• TRK 5522 Reconfigure, 1st Qtr 2024 • Install Relay Panels for TIE4501 and TIE5513 (3rd Qtr 2024) • Prework for TIE4501/TRK 5509 Reconfig, 4th Qtr, 2024) • Reconfig TIE5513, 1st Qtr 2025 • Reconfig TIE1540, 2d Qtr 2025 • Prework TIE4501, 3rd Qtr 2025 • Reconfig TIE4501, 4th Qtr 2025 • Reconfig TIE1531, 1st Qtr 2026 • Decommission TIE5517, 2d Qtr 2026 • Decommission TRK3160, 2d Qtr 2026 • Demo ARGO 40kV yard start 3rd Qtr complete 4th Qtr 2026.			
Budget Basis:	Project Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 17,945,717			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$249,412	\$2,020,165	\$5,921,732
	Material	\$ 40,729	\$371,810	\$397,469
	Other	\$ 43,849	\$608,024	\$2,910,799
	Total	\$333,990	\$3,000,000	\$9,230,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Ann Arbor System Improvements: State Substation
Purpose and Necessity:	This project, coupled with the other Ann Arbor System Improvements Projects will address the following issues: • Reliability: The existing distribution system in the Greater Ann Arbor area experience's frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers. • Capacity: The subtransmission system in Ann Arbor is not adequately sized to accommodate existing load and accelerated load growth in the area. The overloaded system is an impediment to economic growth. • Operability: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 2

(a)

(b)

Program:	Ann Arbor System Improvements: State Substation
Scope:	• Construct a new 120/40 kV Class 'D' station • Establish four subtransmission circuits • Construct a new 120/13.2 kV Class 'A' substation • Decommission the existing State substation and cutover eight distribution circuits to the new substation • Remove overhead on Trunk 7411

(a)

(b)

Program:	Ann Arbor System Improvements: State Substation				
Benefits:	• Provide sufficient capacity to serve existing and new customer load • Reduce equipment risk by providing load relief to the Subtransmission system in the Greater Ann Arbor area to be compliant with the Subtransmission Planning Criteria • Improve system shutdown capability and operability • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Ann Arbor System Improvements: State Substation			
Approximate Construction Schedule:	- Removal of TRK7411 OH, 3rd Qtr 2024; - Resolve manhole hazards to complete removal of 40kV cable for Trans 2 Ingalls and Trans 2 University (start 2d Qtr complete 4th Qtr 2024)			
Budget Basis:	Project Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 72,426,048			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,061,797	\$ 0	\$ 0
	Material	\$ 39,327	\$ 0	\$ 0
	Other	\$442,212	\$ 0	\$ 0
	Total	\$2,543,335	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Alfred Substation Expansion
Purpose and Necessity:	Alfred (ALFRD) is a two transformer Class A substation that serves Detroit’s Central Business District and East Riverfront areas. The City of Detroit Infrastructure Project (CODI) was implemented to align strategies between serving new load and addressing aging infrastructure. This CODI project is proposed to expand ALFRD substation to help to eliminate the 4.8 kV distribution and the 24 kV subtransmission trunk lines in the Midtown area. Drivers for the project include the following: • Capacity: The substation is currently 92% of firm and cannot support the future area load growth. • Operability: Installing a second PDC and a third 24/32/40 MVA transformer along with diversifying exit conduits will improve operability.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 35

(a)

(b)

Program:	CODI: Alfred Substation Expansion
Scope:	• Install a third 24/32/40MVA 120/13.2 kV transformer along with a 12-position switchgear and (3) 40 kA circuit switchers • Install ~3,450' of conduit • Install (11) new manholes • Install 0.5 miles of cable • Install 0.5 miles of fiber optic cable • Remove 0.5 miles of cable

(a)

(b)

Program:	CODI: Alfred Substation Expansion				
Benefits:	• Increase the firm rating of the substation and provide capacity for future load growth including: -Eastern Market Developments (2025) -Garfield Radial load (2026) • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	CODI: Alfred Substation Expansion			
Approximate Construction Schedule:	2022: Detailed Engineering 2023: Design, Order long-lead time equipment 2024: Substation Construction, Conduit Construction and Circuit Cut-Overs			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 24,612,705			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,802,757	\$14,562,709	\$2,715,098
	Material	\$380,008	\$3,672,058	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,182,765	\$18,234,767	\$2,715,098

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: CATO Substation Expansion
Purpose and Necessity:	• Safety: Cato Powerlines like most downtown lines consist of old 4.8 kV or 15kV cable • Reliability: CATO is currently fed by two underground 120 kV lines which cause reliability issues for customers during ITC work and extensive contingency plans • Capacity: Cato 13.2 kV Class “A” is currently at 87% Firm and needs to be expanded to facilitate the future conversions of CATO 4.8 kV and ORCHD 4.8 kV substations • Operability: Should failure occur, repair work could take up to eight weeks for critical customers served with “Cato-Cato” throwovers
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 79

(a)

(b)

Program:	CODI: CATO Substation Expansion
Scope:	• Consolidate and cutover existing (15) Primary Service Customers to nearby 4.8 kV circuits with available capacity (ORCHD/HOWRD/MADSN) • Remove ~25000' P&L cable and install ~2000' cable • Commission three circuits for ORCHD to facilitate load transfer • Decommission CATO 4.8 kV • Remove (2) – 15/20/25 MVA transformers • Remove (2) – PDC • Remove (17) – Circuit Breakers • Remove Buses and associated equipment • Upgrade CATO 13.2 kV to a (3) transformer 120-13.2 kV Class 'A' substation • Install (1) 120 kV-13.2 kV transformer (24/32/40) • Install (1) – 12 position switchgear • Cutover existing 13.2 kV circuits to new PDC • Replace existing 16-position 13.2 kV PDC with a 13.2 kV 12-position PDC • Install (3) capacitor banks • Transfer half of the 13.2 kV Circuits to the second new PDC to balance the loads • Install SCADA on new 13.2 kV transformers and PDC

(a)

(b)

Program:	CODI: CATO Substation Expansion				
Benefits:	• Eliminate need for contingency planning during ITC work on 120 kV lines feeding CATO sub and reduced substation outage risk • Sufficient capacity needed to serve fast growing Detroit core downtown areas • Provide load relief for existing and new customers • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability, and power quality for upgraded circuits				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	CODI: CATO Substation Expansion			
Approximate Construction Schedule:	2021: Engineering 2022: Design 2023: Construction 2024: Commission third transformer			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 37,162,120			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,468,185	\$9,194,175	\$3,840,887
	Material	\$670,664	\$4,977,836	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,138,849	\$14,172,011	\$3,840,887

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Charlotte Network Upgrade
Purpose and Necessity:	Charlotte substation is located in Downtown Detroit and is over 90 years old with no available capacity for incremental load growth. There's been significant recent load growth and development resurgence in the Charlotte area. This project is part of the City of Detroit Infrastructure (CODI) Initiative, directed to eliminate the 4.8 kV and 24 kV voltage classes. The primary driver for this project is to provide capacity for near-term load growth while a secondary driver is the consolidation of assets and replacement of aging infrastructure. • Reliability: This project will consist of replacing aging infrastructure such as cable, netbanks, transformers, and install sectionalizing devices • Capacity: Primary voltage will be converted from 4.8 kV to 13.2 kV which will provide additional capacity in the area for future load growth • Operability: SCADA will be implemented on all future netbanks and netfeeders • Other: Network primary voltage will be converted from 4.8 kV to 13.2 kV to improve safety, reliability, modernize the grid and provide additional capacity in the area for future load growth.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 28

(a)

(b)

Program:	CODI: Charlotte Network Upgrade
Scope:	• Convert and consolidate existing Charlotte 4.8 kV Network to 13.2 kV from Temple Substation • Transfer (2) radial power line customers to adjacent substations • Eliminate network service in areas where it makes sense to provide a different method of service (i.e. URD, OH, etc.) • Decommission (83) 4.8 kV transformers and install (43) 13.2 kV transformers • Decommission (25) miles of cable • Decommission Charlotte substation & 24 kV feeds along with (2) 7.5MVA transformers

(a)

(b)

Program:	CODI: Charlotte Network Upgrade				
Benefits:	• Provide sufficient capacity to serve growing Detroit core downtown areas • Reduce network cable failures and improve manhole safety • Decommission aging infrastructure and reduce major event risk • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost • Invest in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	CODI: Charlotte Network Upgrade			
Approximate Construction Schedule:	2020-2021: Construction and circuit cut-over 2023: Network Energization at 4.8 KV 2024: Network Conversion from 4.8 kV to 13.2 KV 2025: Decommission Charlotte Substation			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 76,879,246			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$5,621,388	\$7,064,311	\$7,655,140
	Material	\$1,993,310	\$2,504,961	\$2,714,466
	Other	\$1,111,930	\$1,397,345	\$1,514,213
	Total	\$8,726,627	\$10,966,617	\$11,883,819

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Corktown Substation
Purpose and Necessity:	Corktown is a general purpose substation that was proposed as part of the CODI upgrade to provide capacity needed to serve fast growing Detroit core downtown areas. This substation will consolidate, convert and eliminate the 4.8 kV distribution and 24 kV subtransmission system in the Corktown/West River Front area. A significant portion of the associated infrastructure (system cable/conductor, circuit breakers) are at end-of-life.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 30

(a)

(b)

Program:	CODI: Corktown Substation
Scope:	• Install a 120/13.2 kV Class 'A' general purpose substation with two 24/32/40 MVA transformers • Install one twelve position switchgear • Install two capacitor banks • Install two circuit breakers • Install two house service transformers • Install 400 feet of 9-5" concrete encased duct bank • Install four three-way manholes • Two (2) duct break-ins (1-labrosse & 1-Porter) • Misc. costs (manhole/duct break-in, permit fees, traffic control, etc.) • Install fiber optic cable between Corktown and downtown complex

(a)

(b)

Program:	CODI: Corktown Substation				
Benefits:	• Provide sufficient capacity needed to serve fast growing Detroit core downtown areas • Provide load relief for existing and new customers • Provide sufficient capacity to serve fast growing Detroit core downtown areas • Decommission aging infrastructure and reduce major event risk				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	CODI: Corktown Substation			
Approximate Construction Schedule:	Substation was commissioned March 2022 Landscaping scheduled for May 2022 Fiber communication scheduled for June/July 2022			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 18,512,911			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$12,420	\$ 0	\$ 0
	Material	\$0	\$ 0	\$ 0
	Other	\$87,844	\$ 0	\$ 0
	Total	\$100,264	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Garfield Network Upgrade
Purpose and Necessity:	The Garfield project is part of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. Garfield substation is to be decommissioned and its circuits converted to nearby 13.2 kV substations. Drivers for the project include the following: • Safety: Garfield substation is a 4.8 kV substation that is over 90 years old • Reliability: A resurgence of development in Detroit in recent years has resulted in increased loading on these aged, often end-of-life assets on both the radial and AC Network system. • Capacity: New 13.2 kV circuits from Midtown substation will support Detroit’s Eastern Market, Milwaukee Junction and Midtown areas, removing load from aging 4.8 kV substations. Approximately 5.5MVA of additional load from new developments in Milwaukee Junction and Midtown cannot be served by the area’s 4.8 kV distribution system. The AC Network has a limited capacity of 2.5MVA remaining. • Operability: New radial circuits will be fully automated, including loop schemes and automated pole top switches. Appropriate sectionalizing devices, automatic and manual, will be installed to isolate circuit to ~200 customers per zone. The AC Network netbanks and netfeeders will have SCADA implemented.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 81

(a)

(b)

Program:	CODI: Garfield Network Upgrade
Scope:	• Replace 36 miles of network feeder cable • Replace or remove 78 netbank transformers • Convert 26 primary customers from 4.8 kV to 13.2 kV • Convert 24 miles of overhead from 4.8 kV to 13.2 kV • Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation

(a)

(b)

Program:	CODI: Garfield Network Upgrade				
Benefits:	• Provide sufficient capacity to serve growing Detroit core downtown areas • Reduce network cable failures and improve manhole safety • Decommission aging infrastructure and reduce major event risk • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Garfield Network Upgrade			
Approximate Construction Schedule:	2020 - 2025: Detailed Engineering, Construct Conduit & Netbanks 2022-2027: Detailed Engineering, Construct Radial Conversion 2023: Network System Cable Installation 2024 - 2025: Energization & Conversion of Network 2025 - 2026: Decommission Network			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 86,808,486			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$14,869,501	\$11,508,562	\$10,102,977
	Material	\$8,520,043	\$5,791,438	\$4,097,023
	Other	\$ 0	\$ 0	\$ 0
	Total	\$23,389,544	\$17,300,000	\$14,200,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Garfield Radial (Midtown Circuits)
Purpose and Necessity:	The Garfield project is part of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. Garfield substation is a 4.8 kV substation that is over 90 years old. It serves the Eastern Market, Forest Park and parts of Art Center and Midtown in Detroit. Due to its aging infrastructure and loading limitations, it is unable to provide sufficient capacity to serve potential developments in the City of Detroit. Garfield substation is to be decommissioned and its circuits converted to nearby 13.2 kV substations. • Safety: Garfield substation is a 4.8 kV substation that is over 90 years old. • Reliability: A resurgence of development in Detroit in recent years has resulted in increased loading on these aged, often end-of-life assets on both the radial and AC Network system. • Capacity: New 13.2 kV circuits from Midtown substation will support Detroit’s Eastern Market, Milwaukee Junction and Midtown areas, removing load from aging 4.8 kV substations. A 5.5 MVA of additional load from new developments in Milwaukee Junction and Midtown cannot be served by the area’s 4.8 kV distribution system. The AC Network has a limited capacity of 2.5 MVA remaining. • Operability: New radial circuits will be fully automated, including loop schemes and automated pole top switches. Appropriate sectionalizing devices, automatic and manual, will be installed to isolate circuit to ~200 customers per zone. The AC Network netbanks and netfeeders will have SCADA implemented.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 80

(a)

(b)

Program:	CODI: Garfield Radial (Midtown Circuits)
Scope:	• Convert 17.2 miles of overhead from 4.8 kV to 13.2 kV • Convert 11 primary customers from 4.8 kV to 13.2 kV • Convert and consolidate the circuits to 13.2 kV fed by Midtown substation • Install 6,800' of new 15kV cable for new Midtown circuits • Install terminations at Midtown substation for MIDTN DC8576, MIDTN 8564 & MIDTN8589 • Remove terminations for (7) 4.8 kV circuits (GARFD1179,GARFD17,GARFD113,GARFD1132,FRISB1267,FRISB409,FRISB2194) • Decommission ~5 miles of UG cable

(a)

(b)

Program:	CODI: Garfield Radial (Midtown Circuits)				
Benefits:	• Provide sufficient capacity to serve growing Detroit core downtown areas • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability, and power quality for upgraded circuits by reducing circuit wire down events, customer interruptions, and customer minutes • Reduce trouble events and reactive costs for upgraded circuits for both circuit tree related and non-tree related reactive capital • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Garfield Radial (Midtown Circuits)			
Approximate Construction Schedule:	2022 - 2025: Detailed Engineering, Overhead Pre-Conversion, Primary Services Pre-Conversion 2026: Conversion to 13.2 kV			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 54,891,009			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,606,352	\$9,020,443	\$ 0
	Material	\$547,094	\$2,612,834	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,153,446	\$11,633,277	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Howard Conversion
Purpose and Necessity:	The Howard Conversion project is part of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. Drivers for the project include the following: • Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. Decommissioning the Howard AC network and replacing with 13.2 kV will eliminate this hazard. • Reliability: Howard substation was commissioned in 1930 and has aging equipment that is at end of life. Aging equipment holds higher risk of failure, potentially causing extensive outages. Replacing this old equipment with new equipment will decrease this risk. • Capacity: To provide sufficient capacity to serving the growing Detroit areas and improve reliability, the Howard AC Network and Howard power lines will be converted and consolidated to new 13.2 kV from TEMPL, STANT, and CATO. • Operability: Converting to 13.2 kV will allow jumpering between other 13.2 kV areas already in service.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 36

(a)

(b)

Program:	CODI: Howard Conversion
Scope:	Project 1 - AC Network Conversion: • Install (41) new netbank transformers • Decommission (6) network feeders, their substation positions/breakers and (9) feeder section switches • Replace or remove 38 netbank transformers and structures • Install (4) 3-way 600A feeder section switches and (8) 2-way 200A feeder section switches • Install (9) 3-way manholes and (1) 2-way manhole and construct over 14,400 feet of conduit • Construct ~43,560' of new AC network system cable Project 2 - Underground Power Line: • Decommission (16) 4.8 kV power lines • Decommission (16) breakers and positions and (27) miles of 4.8 kV cable • Rebuild (12) miles of radial power line system cable • Convert (26) primary customers to 13.2 kV • Convert and consolidate the circuits to 13.2 kV fed by Corktown, Temple, St. Antoine, and Cato substations Project 3 - Howard 24 kV Decommissioning: • Decommission (5) 24 kV Cable: Trunk 787T, Trunk 709T, Trunk 753T, Trunk 764T, Trunk 775T Project 4 - Howard Substation Decommissioning: • Decommission (4) 7.5 MVA transformers, (1) 10 MVA transformer, 1) 10/15 MVA transformer and (1) 12/16 MVA transformer • Decommission (50) oil breakers, (2) vacuum breakers, (5) reactors, (11) regulators, linkage/transfer/circuit/transformer busses

(a)

(b)

Program:	CODI: Howard Conversion				
Benefits:	• Reduce network cable failures and improve manhole safety • Howard 4.8 kV AC network replaced with newer and more reliable 13.2 kV AC network • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality for upgraded circuits • Reduce trouble events and reactive costs for upgraded circuits • Increase protection for the distribution system • Reduce new customer connection timeframe and cost of completing this project. • Increase protection & sectionalizing capabilities for the distribution system • Enhance grid technology and automaton, including DER integration, SCADA capabilities, and fault detection/location				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Howard Conversion			
Approximate Construction Schedule:	2022-2023: Detailed Engineering & Funding 2024: Equipment Purchases 2025-2028: Construction and circuit cut-over 2028-2030: Decommission Howard substation			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 115,099,345			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Islandview Substation - Phase 1
Purpose and Necessity:	Islandview substation and circuit conversion is a key component of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. New customer load from the East Detroit Riverfront cannot be reliably served by the 4.8 kV infrastructure at Walker (WALKR) and Pulford (PULFD) substations. The new Islandview substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system. Walker and Pulford substation have aging infrastructure as they were built over 90 years ago. Many pieces of equipment do not have spare parts available. Some assets have been identified for increased risk of failure including transformers, regulators, oil circuit breakers and disconnects, 4.8 kV and 24 kV underground cable. In addition, the 4.8 kV system in this area experiences wire down events greater than the system average. • Safety: The 4.8 kV distribution system has experienced an average of 108 wire downs per year since 2015. • Reliability: Systems have been dismantled over time due to failures and many pieces of equipment have no spare parts. Many assets are identified as medium/high risk for failure and would require significant time to repair: 23 miles of 90-year-old underground 24 kV cable, 40 miles of 72-year-old underground 4.8 kV cable, 47 oil circuit breakers and disconnects, and 3 transformers and 18 regulators. • Capacity: New customer load has been added along the Detroit riverfront (8.1MVA in 2019 and 2020). Additional developments and conversions from Detroit Public Lighting Department (PLD) are now in service. • Operability: New manholes and switch cabinets will be used to setup the future underground circuits for improved system configuration and operability. Create a link between ALFRD, STANT, and other 13.2 kV circuits.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 31

(a)

(b)

Program:	CODI: Islandview Substation - Phase 1
Scope:	Phase 1 scope: • Construct a new Class 'A' 13.2 kV substation with two transformers and a setup for a future third transformer position • Install ~0.5 miles of substation exit cable and conduit • Install ~4997' of fiber optic cable • Install ~4997' of 3-1.25" conduit

(a)

(b)

Program:	CODI: Islandview Substation - Phase 1				
Benefits:	• Provide sufficient capacity to serve growing areas • Decommission aging infrastructure and reduce major event risk • Increase protection for the distribution system • Enhance grid technology and automation • Reduce new customer connection timeframe and cost • PULFD/WALKR substations have a load capacity of 14.7 MVA, Islandview will have a load capacity of 27 MVA which is a 84% increase. It has potential to have 53.5 MVA load capacity with future expansion which is a 98% increase.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Islandview Substation - Phase 1			
Approximate Construction Schedule:	2021-2022: Design 2022-2023: Construction 2024: Complete			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 23,927,471			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$6,753,544	\$ 6,810	\$ 0
	Material	\$980,385	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$7,733,928	\$ 6,810	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Islandview Substation - Phase 2
Purpose and Necessity:	Islandview substation and circuit conversion is a key component of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. New customer load from the East Detroit Riverfront cannot be reliably served by the 4.8 kV infrastructure at Walker (WALKR) and Pulford (PULFD) substations. The new Islandview substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system. Walker and Pulford substation have aging infrastructure as they were built over 90 years ago. Many pieces of equipment do not have spare parts available. Some assets have been identified for increased risk of failure including transformers, regulators, oil circuit breakers and disconnects, 4.8 kV and 24 kV underground cable. In addition, the 4.8 kV system in this area experiences wire down events greater than the system average. • Safety: The 4.8 kV distribution system has experienced an average of 108 wire downs per year since 2015. • Reliability: Systems have been dismantled over time due to failures and many pieces of equipment have no spare parts. Many assets are identified as medium/high risk for failure and would require significant time to repair: 23 miles of 90-year-old1 underground 24 kV cable, 40 miles of 72-year-old1 underground 4.8 kV cable, 47 oil circuit breakers and disconnects, and 3 transformers and 18 regulators. • Capacity: New customer load has been added along the Detroit riverfront (8.1MVA in 2019 and 2020). Additional developments and conversions from Detroit Public Lighting Department (PLD) are now in service. • Operability: New manholes and switch cabinets will be used to setup the future underground circuits for improved system configuration and operability. Create a link between ALFRD, STANT, and other 13.2 kV circuits.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 32

(a)

(b)

Program:	CODI: Islandview Substation - Phase 2
Scope:	Phase 2 scope: • Pre-Convert and convert existing 4.8 kV circuits from Walker Substation - 2 circuits • Pre-Convert and convert existing 4.8 kV circuits from Pulford Substation - 7 circuits • Convert 32 miles of overhead from 4.8 kV to 13.2 kV • Convert 1 mile of underground from 4.8 kV to 13.2 kV • Convert 11 primary customers from 4.8 kV to 13.2 kV • Install 10 sectionalizing devices

(a)

(b)

Program:	CODI: Islandview Substation - Phase 2				
Benefits:	• 13.2 kV would provide contingencies for existing and future 13.2 kV • 13.2 kV is projected to be able to handle future electrification and electric vehicle load • Installing SCADA and loop schemes on future 13.2 kV circuits • Flexibility to further increase 13.2 kV capacity is available, as needed, via the following: ○ Alfred expansion ○ Islandview expansion ○ Future 120-13.2 kV Promenade substation ○ Build a new substation on available property to the East				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Islandview Substation - Phase 2			
Approximate Construction Schedule:	2022-2023: Design 2023-2025: Preconversion and Conversion construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 59,023,210			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$27,644,262	\$7,779,105	\$11,638,823
	Material	\$8,203,075	\$220,895	\$361,177
	Other	\$ 0	\$ 0	\$ 0
	Total	\$35,847,337	\$8,000,000	\$12,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Islandview Substation - Phase 3
Purpose and Necessity:	Islandview substation and circuit conversion is a key component of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. New customer load from the East Detroit Riverfront cannot be reliably served by the 4.8 kV infrastructure at Walker (WALKR) and Pulford (PULFD) substations. The new Islandview substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system. Walker and Pulford substation have aging infrastructure as they were built over 90 years ago. Many pieces of equipment do not have spare parts available. Some assets have been identified for increased risk of failure including transformers, regulators, oil circuit breakers and disconnects, 4.8 kV and 24 kV underground cable. In addition, the 4.8 kV system in this area experiences wire down events greater than the system average. • Safety: The 4.8 kV distribution system has experienced an average of 108 wire downs per year since 2015. • Reliability: Systems have been dismantled over time due to failures and many pieces of equipment have no spare parts. Many assets are identified as medium/high risk for failure and would require significant time to repair: 23 miles of 90-year-old1 underground 24 kV cable, 40 miles of 72-year-old1 underground 4.8 kV cable, 47 oil circuit breakers and disconnects, and 3 transformers and 18 regulators. • Capacity: New customer load has been added along the Detroit riverfront (8.1MVA in 2019 and 2020). Additional developments and conversions from Detroit Public Lighting Department (PLD) are now in service. • Operability: New manholes and switch cabinets will be used to setup the future underground circuits for improved system configuration and operability. Create a link between ALFRD, STANT, and other 13.2 kV circuits
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 33

(a)

(b)

Program:	CODI: Islandview Substation - Phase 3
Scope:	Phase 3 scope: • Install approximately 33,000' of new 5" system conduit • Install (35) new manholes and install (14) new primary switch cabinets to optimize underground circuit configuration

(a)

(b)

Program:	CODI: Islandview Substation - Phase 3				
Benefits:	• Directs Islandview Substation capacity through modern infrastructure to facilitate 4.8 kV conversion and eliminating aging assets at Walker and Pulford. • New manholes and switch cabinets will be used to setup the future underground circuits for improved system configuration and operability. • The new underground system will provide increased reliability, capacity, and operability for DTE and its customers.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Islandview Substation - Phase 3			
Approximate Construction Schedule:	2024: Engineering/Design 2025: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 65,045,392			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Kent/Gibson Conversion - Phase 1
Purpose and Necessity:	The Kent/Gibson Conversion project is part of the greater City of Detroit Infrastructure (CODI) which was implemented to serve new load and address aging assets. This project will help serve load along the West Detroit Riverfront which currently can't be served reliably with the 4.8 kV infrastructure. The project will utilize the newly built 13.2 kV Corktown substation to convert and consolidate the 4.8 kV in the area to 13.2 kV. Drivers for this project include the following: • Reliability: Gibson substation was built in 1948 with aging infrastructure and at-risk equipment. 100% of the system cable at Gibson substation is considered at-risk. Kent substation was built in 1960 and contains at risk equipment. 99% of the system cable at Kent substation is considered at-risk. Kent and Gibson substations both experience outages which exceed the system average. • Capacity: Gibson substation is 101% of its firm rating with the potential of 6.9 MVA stranded load. Kent substation is 72% of its firm rating and the individual circuits have limited capacity. • Operability: Kent and Gibson circuits currently do not have any loop schemes and have limited to no sectionalizing. Neither substation has any automatic operating points nor have limited protective devices.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 82

(a)

(b)

Program:	CODI: Kent/Gibson Conversion - Phase 1
Scope:	• Consolidate, pre-convert & convert (6) KENT4.8 kV circuits to CORKT 13.2 kV • Consolidate, pre-convert & convert (8) GIBSN 4.8 kV circuits to CORKT 13.2 kV • Consolidate, pre-convert & convert (2) SCOTN 4.8 kV circuits to CORKT 13.2 kV • Consolidate, pre-convert & convert (3) HOWRD 4.8 kV circuits to CORKT 13.2 kV • Convert (17) primary customer from 4.8 kV to 13.2 kV • Decommission 8 miles of 4.8 kV cable • Remove (8) 4.8 kV breakers and decommission Kent substation • Remove (11) 4.8 kV breakers and decommission Gibson substation • Decommission 16 miles of 24 kV cables and equipment

(a)

(b)

Program:	CODI: Kent/Gibson Conversion - Phase 1				
Benefits:	• Reduce substation outage risk by replacing aging infrastructure • Enhance safety, reliability, and power quality • Provide sufficient capacity to serve existing and new customer load • Reduces circuit level exposure by removing double build on OH • Reduces all outages related to trees, equipment and loads • Provides operability with automated loop schemes • Eliminates 4.8 kV and 24 kV infrastructure • Removes all "at risks" equipment and cable at substation • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	CODI: Kent/Gibson Conversion - Phase 1			
Approximate Construction Schedule:	2021: Phase 1 Engineering - CORKT8604, CORKT8353 2022: Phase 1 Detailed Design & Construction - CORKT8604, CORKT8353 2023: Phase 1 Construction - CORKT8604, CORKT8353 - Preconvert Phase 2 Engineering & Design - CORKT8492 Phase 4 Engineering - CORKT8562, CORKT8507 2024: Phase 1 Construction - CORKT8604, CORKT8353 - Convert Phase 2 Construction - CORKT8492 Preconvert Phase 4 Detailed Design - CORKT8562, CORKT8507 2025: Phase 2 Construction - CORKT8492 Convert Phase 3 Engineering, Detailed Design - KENT decommissioning, 24 kV decommissioning Phase 4 Construction - CORKT8562, CORKT8507 Preconvert 2026: Phase 2 Construction - CORKT8492 Convert Phase 3 Construction- KENT decommissioning, 24 kV decommissioning Phase 4 Construction - CORKT8562, CORKT8507 Convert 2027: Phase 5 Engineering, Detailed Design, Construction - GIBSN decommissioning, 24 kV decommissioning			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 51,173,654			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$7,177,195	\$11,249,782	\$ 0
	Material	\$1,667,552	\$3,856,917	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$8,844,746	\$15,106,699	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CODI: Midtown Substation Expansion
Purpose and Necessity:	The Midtown Substation Expansion project is part of the City of Detroit Infrastructure (CODI) plan which addresses loading and aging infrastructure. Midtown (MIDTN) is a 2 transformer Class 'A' general purpose substation constructed in 1973 that serves downtown Detroit New Center and Midtown areas. This project will expand MIDTN substation. Drivers for this project include the following: • Capacity: The substation is currently 81% of firm and cannot support approximately 20 MVA of future known load growth. The new load growth would place the substation at 146% of its firm rating. • Operability: Installing a second PDC and a third 24/32/40 MVA transformer along with diversifying exit conduits will improve operability.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 34

(a)

(b)

Program:	CODI: Midtown Substation Expansion
Scope:	• Install a third 120/13.2 kV 24/32/40MVA transformer • Install 12 position switchgear • Install (2) capacitors • Install ~1,300 feet of concrete encased duct bank • Install (7) new manholes • Misc. costs (manhole/duct break-in, permit fees, traffic control, etc.)

(a)

(b)

Program:	CODI: Midtown Substation Expansion				
Benefits:	• Provide sufficient capacity needed to serve fast growing Detroit core downtown areas • Provide load relief for existing and new customers • Implement SCADA capabilities at Midtown substation				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	CODI: Midtown Substation Expansion			
Approximate Construction Schedule:	2018: Engineering/Detailed Design 2018-2020: Detailed Design 2020-2024: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 14,421,842			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$840,398	\$458,714	\$ 0
	Material	\$181,317	\$ 0	\$ 0
	Other	\$ 63,741	\$ 0	\$ 0
	Total	\$1,085,456	\$458,714	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism

(a)

(b)

Program:	CODI: Targeted Network Secondary Cable Replacement
Purpose and Necessity:	This cable program is designed to replace targeted 4.8 kV secondary network cable system in Detroit that has a higher probability of failure. This will reduce the secondary network cable failures and manhole events in downtown City of Detroit.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 29

(a)

(b)

Program:	CODI: Targeted Network Secondary Cable Replacement
Scope:	• Replace targeted sections of the secondary network cable system that have a higher probability of failure

(a)

(b)

Program:	CODI: Targeted Network Secondary Cable Replacement				
Benefits:	• Reduce secondary network cable failures and enhance manhole safety • Replace aging infrastructure and reduce major event risk • Enhance safety, reliability and power quality • Reduce reactive costs associated with secondary cable failures				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	CODI: Targeted Network Secondary Cable Replacement			
Approximate Construction Schedule:	Annual Program 2024 – 10,700 feet 2025 – 7,400 feet			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,325,266	\$2,313,802	\$2,766,702
	Material	\$1,641,070	\$1,486,198	\$1,033,298
	Other	\$327,736	\$ 0	\$ 0
	Total	\$4,294,071	\$3,800,000	\$3,800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Pilot: Primary Deconductoring
Purpose and Necessity:	This is a pilot to deconductor specific circuits, in areas that have seen significant population decline, with a goal of removing underutilized infrastructure that is no longer needed. Work is being done to reduce the number of wire downs and assets in unoccupied areas. This work will decrease the wire down exposure and outage events. This program will reduce the number of assets which will result in lower tree trimming and PTMM costs. This program will also reduce the scope of the 4.8 kV Hardening by reducing the number of pole tops. Circuits will be evaluated based on their peak demand and vacant parcels to determine if they fit this program. After selecting circuits, voltage drop will be calculated per lateral to see effects of removing primary conductor and transformers. After determining voltage drop, primary conductor and transformers on lateral will be removed, secondary will be reconducted where necessary, and transformers will be installed in truck accessible circuit backbone locations.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 65

(a)

(b)

Program:	Pilot: Primary Deconductoring
Scope:	• Deconductor pockets of sparsely occupied areas within the City of Detroit by removing primary wire and hardware. • Remove approximately 19,000 feet of small primary and arc circuit in rear lots along with pole tops • Remove rear lot distribution transformers • Install truck accessible transformers • Reconductor approximately 10,500 feet of secondary conductor • Perform necessary spot line clearance

(a)

(b)

Program:	Pilot: Primary Deconductoring				
Benefits:	• Reduce the number of wire downs • Reduce the number of outage events • Lower tree trimming and PTMM costs • Reduce the need for 4.8 kV Hardening • Reduce restoration timing				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Pilot: Primary Deconductoring			
Approximate Construction Schedule:	RELI0357 – CLOSEOUT RELI0412 – CLOSEOUT RELI0441-01 – CLOSEOUT RELI0441-02 – CONSTRUCTION COMPLETED, CLOSEOUT RELI0441-03 – ENG, DSG, CNST, CLOSEOUT RELI0441-04 - ENG, DSG, CNST, CLOSEOUT RELI0441-05 – ENG, DSG, CNST, CLOSEOUT			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,313,873			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 25,881	\$ 0	\$ 0
	Material	\$ 9,906	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 35,787	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Pilot: Strategic and Service Undergrounding
Purpose and Necessity:	One of the planning scenarios described in the 2021 DGP considers changing weather patterns that lead to an increasing number of catastrophic storms. Although storm resiliency programs like tree trimming, hardening, PTMM, and customer excellence are established to provide customers the needed reliability for this scenario, in some areas they may not completely resolve the issue. In these situations, Strategic Underground may be a good option. Furthermore, the Company's customers have been impacted by an unusually high number of severe weather events during the summer of 2021. This has driven significant customer interest in undergrounding, and the Company is developing plans to partner with communities to implement based on their interest.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 64

(a)

(b)

Program:	Pilot: Strategic and Service Undergrounding
Scope:	• Apply lessons learned from Appoline pilot undergrounding to developing pilots • Replacing overhead services with underground services • Replacing overhead laterals with URD • Working with communities that have specific needs, and those who may be willing to partner in funding projects • Transfer 600 OH customers to NEW URD in the city of Detroit. 5.1 Miles of Primary, 3.8 Miles of Secondary, and 18.5 miles of conduit as part of the URD construction. (48) New pad mounted transformers, (141) Secondary Handholes, Rebuild PLD and PLD/ARC wire removal, All primary and secondary to be bore in, OH primary and secondary removal.

(a)

(b)

Program:	Pilot: Strategic and Service Undergrounding				
Benefits:	The project will improve reliability and reduce wire downs by significantly reducing exposure to trees and reduce restoration times by making equipment more accessible. • After the project is completed, upstream infrastructure will still have a major impact on SADI. • New assets will be primarily underground significantly reducing exposure of service to tree damage. • Roadside and front yard infrastructure provides easier access to DTE Equipment during outage events. • Primary feeders will be constructed to 15kV standard facilitating future voltage conversions. • Coordinate with gas main replacement to minimize customer disruption from construction. • Reduce public safety hazards and wire down events by removing conductor and overhead infrastructure.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Pilot: Strategic and Service Undergrounding			
Approximate Construction Schedule:	Appoline: Construction 2022-2023 Buffalo-Charles: • Engineering & Design completed in 2024 • OH Construction complete 2023 • Materials 2023 & 2024 • Joint efforts with DTE Gas / UG Construction 2023 through 2024 • OH Removal and Sidewalk/road Restoration 2024/2025 • Services to be installed at customer homes 2024 • Project completion 2025			
Budget Basis:	Engineering Estimate and actuals from Appoline project			
Total Cost: \1	The estimated project cost for this investment is \$ 136,210,705			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,542,873	\$13,016,334	\$14,710,498
	Material	\$1,287,134	\$2,627,506	\$1,308,751
	Other	\$0	\$0	\$0
	Total	\$3,830,006	\$15,643,840	\$16,019,249

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Breaker Short Circuit Violations
Purpose and Necessity:	Safety/Reliability: 20 breakers on the Subtransmission system are in violation of the Subtransmission Planning criteria by exceeding their interrupting ratings. This could result in equipment damage or catastrophic failure of these breaker positions.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 22

(a)

(b)

Program:	Subtransmission Breaker Short Circuit Violations
Scope:	• Replace 7 Breakers & associated relay panels • Install 3 neutral grounding reactors

(a)

(b)

Program:	Subtransmission Breaker Short Circuit Violations				
Benefits:	- Subtransmission breakers will not be exposed to faults they are not capable of interrupting based on the existing breaker's ratings. - Eliminate the possibility for a breaker failure at these locations. - Upgrade breakers and relay panels at these locations to meet current design standards.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Breaker Short Circuit Violations			
Approximate Construction Schedule:	2021: Engineering & Design 2022: Design & Construction 2023-2024: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,572,712			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,077,896	\$ 50,000	\$ 0
	Material	\$644,895	\$ 0	\$ 0
	Other	\$141,116	\$ 0	\$ 0
	Total	\$2,863,906	\$ 50,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: 40 kV Capacitor Banks at Armada and Adair
Purpose and Necessity:	Capacity: Tie 810 is a three-ended tie line consisting of 50 miles of overhead lines serving 10 substations. Low voltage levels are currently seen on this circuit due to significant circuit mileage and load. Voltage violations as low as 89% of nominal voltage are seen in Tie 810 for multiple single contingency scenarios, violating the Subtransmission planning criteria which states that for emergency conditions of a single contingency event (N-1), the voltage limits are 92%-105% of nominal voltage.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 24

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: 40 kV Capacitor Banks at Armada and Adair
Scope:	• Install a new 40 kV capacitor bank at Adair substation • Install new control house, extend substation fence and a new 40 kV capacitor bank at Armada substation.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: 40 kV Capacitor Banks at Armada and Adair				
Benefits:	- The voltage on the circuit will be improved increasing operational flexibility on Tie 810. - This project will also help facilitate the circuit shutdowns needed to construct the Tie 810 reconductoring project.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x			
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: 40 kV Capacitor Banks at Armada and Adair			
Approximate Construction Schedule:	2022-2024: Engineering, Design & Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 6,696,067			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,314,520	\$206,598	\$ 0
	Material	\$402,306	\$ 53,792	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,716,827	\$260,390	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
Purpose and Necessity:	- Capacity: The tie lines out of Bad Axe (Badax) station experience low voltage violations with the loss of Bad Axe Transformer 101, violating the Subtransmission Planning Criteria. - Operability: The System Operations Center restricts shutdowns on Bad Axe Transformer 101 to prevent this low voltage. During an outage, manual load shed up to 23.4 MVA would be return the voltage to our operating limits.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 74

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
Scope:	• Install 1 station transformer Install • Install 1 bus • Install 2 breakers • Install 4 disconnects • Install 1 circuit switcher • Install new control house and 3 relay panels • Replace 1 capacitor

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • Alleviate voltage violations, and the possibility of shedding customer load during a single contingency event. • Improve system shutdown capability and operability.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition			
Approximate Construction Schedule:	2022: Design & material order 2023: Design & Construction 2024: Construction & In-commission Project has been approved by ITC. Construction will need to be coordinated with ITC.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 11,423,917			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$887,141	\$ 33,604	\$5,043,915
	Material	\$671,292	\$546,396	\$838,259
	Other	\$118,972	\$ 0	\$ 0
	Total	\$1,677,405	\$580,000	\$5,882,174

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Boyne
Purpose and Necessity:	• Capacity: Trunk 7909 is loaded to 120% of its summer emergency rating and Trunk 6759 is loaded to 107% of its summer emergency rating, violating the Subtransmission Planning Criteria. The criteria states emergency loading on the subtransmission system (resulting from the forced outage of any single element, N-1) shall not exceed 90% of the emergency rating of equipment. These two trunk lines have no remaining capacity for new load. • Operability: Load will be automatically shed at Omega and Beach Substations to prevent this equipment overload.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 12

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Boyne
Scope:	<u>Trunk 7909</u> • Replace 2.1 miles of overhead conductor on TRUNK7909 <u>Trunk 6759</u> • Install 0.4 miles of underground cable • Remove 0.2 miles of underground cable • Replace 0.03 miles of overhead conductor <u>Boyne Station</u> • Install 1 station transformer • Install 1 station bus • Install 1 circuit switcher • Install 3 breakers • Install 4 disconnects • Install 3 relay panels • Install 1 capacitor <u>Trunk 7291</u> • Install 1.5 miles of underground cable • Install 2.5 miles of overhead conductor

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Boyne				
Benefits:	• Eliminate equipment thermal overloads for Trunk 7909 • Eliminate equipment thermal overloads for Trunk 6759. • Eliminate load shed for a single contingency outage or shutdown events. • Provide capacity for future load growth. • Investment in an EJ community				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Boyne			
Approximate Construction Schedule:	2020: Engineering 2021: Design Trunk 7909/Construction Trunk 7909 2022: Construction Trunk 7909/Project close out 2023: Construction Station 2024: Construction/ Project close out Construction of Boyne Station expansion will need to be coordinated with ITC.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 28,620,273			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$5,526,276	\$1,459,839	\$ 0
	Material	\$2,782,879	\$654,552	\$ 0
	Other	\$0	\$912,014	\$ 0
	Total	\$8,309,155	\$3,026,405	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Cortland Station Expansion
Purpose and Necessity:	• Reliability: Cortland Station was identified as a high-risk station in the Operational Risk Assessment. • Operability: The existing station transformers at Cortland have physical constraints that do not allow for replacement in their existing locations. If a transformer failure were to occur, there are minimal options to serve the load if the next contingency were to occur. Many portable generators would be required.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 78

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Cortland Station Expansion
Scope:	• Replace 2 station transformers • Install 2 circuit switchers • Install 600 feet of conduit • Install 600 feet of cable

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Cortland Station Expansion				
Benefits:	Significantly reduce the risk of losing approx. 49,255 customers & two industrial substations in Highland Park and Detroit served from Cortland Transformer 101, 102, and 103.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Cortland Station Expansion			
Approximate Construction Schedule:	Project will require MTEP approval (approx. 18 months) 2023-2025: Engineering (ITC relocations must be completed prior to DTE Station work) 2026: Design & material purchase 2027: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 7,655,693			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 40,417	\$101,125	\$108,700
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 40,417	\$101,125	\$108,700

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Maxwell Amherst
Purpose and Necessity:	Operability: Amherst industrial substation was partially relocated to Maxwell station during an trouble/emergent job. The drivers for this project is to fully relocate Amherst industrial substation to Maxwell to meet the industrial customer service needs.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 6

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Maxwell Amherst
Scope:	Work at Amherst: - Decommission and remove: one transformer, two capacitors, and a 120 kV underground cable between Maxwell - Amherst - Decommission old audio-tone transfer trip scheme between DTEE and the customer sites - Decommission DTE relays at customer's switch house Work at Maxwell: - Install one transformer at Maxwell position HR - Decommission and remove Maxwell position HP circuit switcher - Install/Replace three circuit switchers at Maxwell position HQ, HR, and HD - Install 2,000 feet of 13.2 kV underground cable from Transformer 2 secondary to customer's manhole and splice with customer's cable - Install one SCADA/Power Quality meter with ethernet connection at Maxwell - Install new transfer trip scheme between the customer and Maxwell using radio communication and relays

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Maxwell Amherst				
Benefits:	- Correct impedance and improved equipment serviceability for the customer due to both transformers being the same type and distance from the customer, as well as located at the same site - Reduce equipment risk of failure by replacing Transformer 2 serving the customer				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Maxwell Amherst			
Approximate Construction Schedule:	Construction completed 2023			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 3,780,195			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$141,789	\$ 0	\$ 0
	Material	\$ 18,124	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$159,913	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Praxair
Purpose and Necessity:	Operability: The normally open section disconnect at Praxair Substation (Position HL) is not rated high enough to interrupt the transformer magnetizing current, load current, or loop current. Therefore, the customer's operation needs to be interrupted every time the switch needs to be operated. The number of shutdowns currently required for DTE maintenance activities greatly impacts the primary customer's business and coordination of this work is challenging.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 20

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Praxair
Scope:	Praxair - River Rouge 2 • Remove 2 spans of 120 kV overhead wire from Tower 9483 to substation entrance H frame • Remove trainers from entrance H frame to disconnect “HP” • Route ~800ft 120 kV overhead wire on steel poles from Tower 9483 on south side of Great Lakes Ave to new H frame • Construct new H frame in “future Transformer 3” location on key plan & install new normally closed disconnect “HX” at its base • Install two new normally open section breakers (between bus 101-103 and bus 104-105) • Substation modifications/upgrades ○ Remove operating mechanism from disconnect “HL”, leave permanently open & decommission in place ○ Conductor through from Bus 101 to disconnect “HP” ○ Replace previously decommissioned in place disconnect “HQ” with new normally-closed disconnect ○ Upgrade Praxair 1 RTU & alarm panel • River Rouge - Ironton 1 ○ Remove 1 span overhead wire from last steel pole outside of substation fence to disconnect “HS” ○ Install new H frame at east most side of Bus 105 & install new disconnect “HY” at its base ○ Extend ~320 ft of overhead wire on steel poles outside of the substation fence to new H-frame

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Praxair				
Benefits:	- Increased operational flexibility at the site for future shutdowns for DTE planned maintenance activities - No restrictions on opening/closing of breaker like with disconnect HL - Eases some of customer's frequency of shutdown concerns - Implements the minimal scope to appease one of our largest customers - Taking advantage of existing space in key plan to install new line entrance and section breakers - Fixes minimal approach distance concern with Praxair – River Rouge 2 line above switcher HD - By installing normally open section breaker (instead of N.C.) DTE remains owner of the 120 kV assets at the site - All of Linde's plants could be in service for any sect breaker maintenance – instead of prolonged shutdown required for maintenance on section disconnect HL 2/3 of Linde's plants could be in service for disconnect (HP, HN, HV, HS) maintenance - Plant 8 load could be served via Praxair – River Rouge 2 for work/trouble on River Rouge – Ironton 1 - River Rouge – Ironton 1 could serve load of Plant 7, if necessary				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x		

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Praxair			
Approximate Construction Schedule:	2022, 2023: Engineering 2024, 2025: Design and Construction Project will require ITC's LDC approval and construction will need to be coordinated with ITC.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,554,617			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$564,800	\$1,265,417
	Material	\$ 0	\$ 0	\$734,583
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$564,800	\$2,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program
Purpose and Necessity:	Operability: Currently, to allow some of ITC shutdowns to be perform, DTE Operations has to pre-contingent set-up specific areas for load rejection due to the next contingency loss of another equipment (N-1-1) resulting in power to flow from the 40 kV (or 24 kV) to the 120 kV system through DTE Transformers (120/24 kV or 120/40 kV) to serve the distribution substation load or industrial load connected to the ITC system. To pre-contingent set-up specific areas for load rejection, DTE has to open breakers on the 40 kV (or 24 kV) system to prevent post-contingency backfeeding. If this back-feed condition occurs then this would result in (1) severe overloads and/or low voltage conditions on the DTE system which could lead to cascading outages, damage DTE & customer equipment and (2) there would be lack of protection since there is no longer the ability to detect phase to ground faults on the 120 kV system because it is a delta system and will operate like DTE 4.8 kV system which is a major safety concern. The DTE system has to be set-up for load rejections prior to starting ITC shutdown. These operating actions create additional work on DTE's side for switching, often reduces system reliability, and frequently can introduce additional restrictions on much needed shutdowns. This has resulted in ITC Operations requesting DTE to install reverse relay schemes at various locations.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 72

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program
Scope:	• Bad Axe TRF 101 already has a new panel being installed in 2022, relay resets will be required to enable the 32 function. • Bennett TRF 102 will require a new panel replacement. • Chelsea TRF 101 will require a SEL relay replacement. • Chestnut TRF 101 will require a SEL relay replacement. • Chestnut TRF 102 will require a SEL relay replacement. • Cortland TRF 101 will require a SEL relay replacement. • Cortland TRF 102 already has a new relay panel with the 32 scheme enabled (field needs to confirm if panel is in service). • Cortland TRF 103 already has a new panel, relay resets will be required to enable the 32 function. • Custer TRF 101 requires a new relay panel replacement. • Custer TRF 103 already has a new relay panel, however a relay replacement is required. • Lark TRF 101 has a new panel replacement design in progress however a relay replacement is required. • Rush TRF 101 already has a new relay panel, however a relay replacement is required. • Lee TRF 101 will require a new relay panel replacement. • Red Run TRF 101 will require a new relay panel replacement. • Redrun TRF 102 will require a new relay panel replacement. • Redrun TRF 103 already has a new relay panel, however relay resets will be required to enable the 32 function. • Victor TRF 101 will require a new relay panel replacement. • Victor TRF 102 will require a new relay panel replacement. • Spokane TRF 101 will require a new relay panel replacement. • Spokane TRF 103 will require a new relay panel replacement. • Hancock TRF 102 will require a new relay panel replacement.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program				
Benefits:	- Improved operability of the subtransmission system - Reduction in load shed				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program			
Approximate Construction Schedule:	2024: Engineering & Design 2025-2028: Design & Construction Construction may require coordination with ITC for shutdowns. Shutdowns will be limited to a certain system load level for each location.			
Budget Basis:				
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$150,000	\$503,095
	Material	\$ 0	\$ 0	\$396,905
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$150,000	\$900,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
Purpose and Necessity:	Capacity: Sandusky Transformer 101 is loaded to 126% of the equipment's summer normal rating, violating the Subtransmission Planning Criteria. The criteria states that the day to day loading (normal, N-0) on the subtransmission system shall not exceed 100% of the day to day rating of equipment. In the event an equipment failure occurs at Sandusky Transformer 101 due to overload, customers would experience low voltage and be at risk of load shed for an extended period of time until permanent repairs were made.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 11

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
Scope:	• Replace 1 disconnect • Replace Current Transformers • Replace 1 relay panel

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker				
Benefits:	- Eliminate thermal loading violation of the Subtransmission Planning Criteria. - Prevent equipment failure at Sandusky Transformer 101 due to thermal overload which could result in customer low voltage events, curtailed wind park generation, and extensive contingency plans and portable generation to restore customers.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x			
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker			
Approximate Construction Schedule:	2022: Engineering 2023: Engineering/Design 2024: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,069,635			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 67,250	\$1,095,405	\$ 0
	Material	\$ 0	\$173,456	\$ 0
	Other	\$ 0	\$2,800,774	\$ 0
	Total	\$ 67,250	\$4,069,635	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Slocum
Purpose and Necessity:	Other: The Trenton Channel Power Plant (TCHPP), including all outlying structures and buildings are planned for retirement in 2022 with subsequent demolition. Trunk 1110, Trunk 1116, Trunk 1140 will be redesigned to remove all unused equipment that is currently being used to feed system service transformers at the power plant.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 23

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Slocum
Scope:	• Remove 0.8 miles of overhead conductor • Remove 0.9 miles of underground cable • Remove 2 pole top switches • Remove 1 breaker • Remove 1 disconnect • Install 150 feet of conduit

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Slocum				
Benefits:	This work will support the decommissioning of TCHPP. The redesign of the subtransmission circuits will help improve the reliability by eliminating unnecessary exposure to potential outages in the electric system and by removing unused aging infrastructure. The removal of unused underground cables will also free up underground ducts that can be used for future projects in the area.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:				x	

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Slocum			
Approximate Construction Schedule:	2023: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 572,679			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$438,798	\$ 0	\$ 0
	Material	\$ 72,405	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$511,203	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Small Projects & Reserve
Purpose and Necessity:	This category includes small projects aimed at addressing thermal overloads and voltage violations on the subtransmission system: <u>Trunk 2508</u> • Capacity: Trunk 2508 is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria. • Operability: Load will automatically be shed at Centerline substation to prevent this equipment overload. <u>Trunk 2506</u> • Capacity: Trunk 2506 section is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria. • Operability: Load will automatically be shed at Centerline substation to prevent this equipment overload. <u>Trunk 7114-7115:</u> • Capacity: Trunk 7114-7115 is loaded to 120% of its emergency rating, exceeding the Subtransmission planning criteria. • Operability: Load will automatically be shed at Sargent and Gary substations to prevent this equipment overload.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 21

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Small Projects & Reserve
Scope:	This category addresses small and localized overload conditions and voltage violations on the Subtransmission system. Individual project scope will be small. Some projects identified for this program include: • Trunk 2508 – Replace approx. 352 feet of existing 24 KV underground cable from Cable Pole 1 to Centerline substation Transformer 1. Install 3 straight joints. Install new termination at Cable Pole 1 and Centerline substation Transformer 1. • Trunk 2506 – Replace approx. 287 feet of existing 24 KV underground cable from Cable Pole 1 to Centerline substation Transformer 2. Install 2 straight joints. Install new termination at Cable Pole 1 and Centerline Transformer 2. • Trunk 7115 – Replace approx. 133 feet of existing 40 KV underground cable from Southfield station Position RR to MH 16903. Install 1 straight joint on and 1 transition joint. Install new EPR termination at Southfield station Position RR. • Trunk 7114 – Replace approx. 145 feet of existing 40 KV underground cable from Southfield Position RR to MH 16903. Install 1 straight joint and 1 transition joint. Install new EPR termination at Southfield station Position RR.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Small Projects & Reserve				
Benefits:	• Eliminate thermal loading violation of the Subtransmission Planning Criteria. • Eliminate customer low voltage events and violations of the Subtransmission Planning Criteria. • Prevent customer load shed for a single contingency event.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x			
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Small Projects & Reserve			
Approximate Construction Schedule:	2023: Engineering & Design 2024: Design & Construction 2025: Construction			
Budget Basis:	Blanket funding			
Total Cost: \1	The estimated project cost for this investment is \$ 504,042			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 4,042	\$365,353	\$ 0
	Material	\$ 0	\$134,647	\$ 0
	Other	\$ 0	\$0	\$ 0
	Total	\$ 4,042	\$500,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 1568
Purpose and Necessity:	Capacity: Tie 1568 is loaded to 99% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria. Operability: There is an Emergency Load Control scheme at CROWN substation that will automatically shed load (10.1 MVA) to protect from overloading equipment and causing permanent damage
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 16

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 1568
Scope:	• Remove/Install 0.2 miles of underground cable on CROWN tap. • Replace existing Cable Pole 1 with steel pole.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 1568				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • New equipment ratings lower the percent of capacity utilized by the current system loading. • Improve system shutdown capability and operability.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 1568			
Approximate Construction Schedule:	2022: Design 2023: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 723,145			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$441,842	\$ 0	\$ 0
	Material	\$155,091	\$ 0	\$ 0
	Other	\$47,843	\$ 0	\$ 0
	Total	\$644,776	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 3205
Purpose and Necessity:	Reliability: Tie 3205 experienced 11 sustained and 36 momentary outages within the past 3 years. Most of Tie 3205 is in deep easement or right-of-way which contributes to the poor reliability.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 71

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 3205
Scope:	• Replace 1 breaker • Replace 2 disconnects • Replace 1 relay panel • Install 29.5 miles of overhead conductor • Remove 25.6 miles of overhead conductor • Install 6 pole top switches • Remove 8 pole top switches

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 3205				
Benefits:	- Improved reliability with new conductor and rebuilding out of deep easement. - Eliminate possible environmental impacts from oil filled breaker.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:			x	x	

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 3205			
Approximate Construction Schedule:	2022: Scoping 2023: Engineering & pre-design 2025: Design ~6 miles & Right of Way/Easements/Vegetation agreements 2026: Design ~10 miles / Construction 6 miles 2027: Design ~11 miles & Substation / Construction ~10 miles 2028: Construction ~11 miles & Substation breaker replacement			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 53,037,429			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$451,095	\$ 0	\$1,375,000
	Material	\$340,008	\$ 0	\$2,625,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$791,103	\$ 0	\$4,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4104
Purpose and Necessity:	Reliability: Tie 4104 has experienced frequent outages and deterioration of the conductor has been identified from testing.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 73

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4104
Scope:	• Replace 18 miles of overhead conductor • Install 1 circuit switcher • Replace control house at Talbot Substation • Install 2 Automatic pole top switches • Replace 3 manual pole top switches • Replace 1 breaker • Replace 18 miles of distribution underbuild conductor and associated equipment

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4104				
Benefits:	• Reduce safety risk, to customers and crews, of wire down events with new conductor • Improve customer reliability and power quality with less outage events and better voltage support with new conductor • Reduce reactive trouble cost by approximately 20% for Tie 4104 and associated underbuilt distribution circuits				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4104			
Approximate Construction Schedule:	2022 Engineering 2023 Engineering 2024 Funding Deferred 2025 Design/Construction 2026 Construction 2027 Construction 2028 Construction/Closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 36,624,495			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1
Purpose and Necessity:	Reliability: • Tie 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing subtransmission lines. Lightning causes phase to phase faults, due to lack of lightning protection, leading to breaker operations. • Tie 4105 pole inspection data has shown that a high number of wood poles are deteriorated and require replacement. Sections of conductor from this tie line have been evaluated. It has been determined that the steel core is deteriorated, and the remaining tensile strength is greatly reduced. The conductor has been determined to be at the end of its life based on this evaluation. • The existing Tie 4105 is built in deep right-of-way, which contributes to frequent outages from tree interference as well as longer outage duration due to the line not being truck accessible. There are 3,453 customers directly impacted by the reliability of Tie 4105.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 13

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1
Scope:	• Reconductor 6.7 miles of overhead conductor • Replace 2 automatic pole top switches • Replace 2 manual pole top switches • Rebuild 4.4 miles of distribution under build

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1				
Benefits:	• Reduce wire outage events and durations. • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1			
Approximate Construction Schedule:	2020: Design 2021-2023: Design & Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 16,473,064			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,352,799	\$ 0	\$ 0
	Material	\$ 94,950	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$1,447,749	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2
Purpose and Necessity:	Reliability: • Tie 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing subtransmission lines. Lightning causes phase to phase faults, due to lack of lightning protection, leading to breaker operations. • Tie 4105 pole inspection data has shown that a high number of wood poles are deteriorated and require replacement. Sections of conductor from this tie line have been evaluated. It has been determined that the steel core is deteriorated, and the remaining tensile strength is greatly reduced. The conductor has been determined to be at the end of its life based on this evaluation. • The existing Tie 4105 is built in deep right-of-way, which contributes to frequent outages from tree interference as well as longer outage duration due to the line not being truck accessible. There are 3,453 customers directly impacted by the reliability of Tie 4105.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 68

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2
Scope:	• Reconductor 9.2 miles of overhead conductor • Rebuild 3.9 miles of distribution under build

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2				
Benefits:	• Reduce wire outage events and durations. • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2			
Approximate Construction Schedule:	2024: Engineering 2025-2026: Design & Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 11,295,741			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3
Purpose and Necessity:	Reliability: • Tie 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing subtransmission lines. Lightning causes phase to phase faults, due to lack of lightning protection, leading to breaker operations. • Tie 4105 pole inspection data has shown that a high number of wood poles are deteriorated and require replacement. Sections of conductor from this tie line have been evaluated. It has been determined that the steel core is deteriorated, and the remaining tensile strength is greatly reduced. The conductor has been determined to be at the end of its life based on this evaluation. • The existing Tie 4105 is built in deep right-of-way, which contributes to frequent outages from tree interference as well as longer outage duration due to the line not being truck accessible. There are 3,453 customers directly impacted by the reliability of Tie 4105.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 14

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3
Scope:	• Reconductor 6.7 miles of overhead conductor • Replace 2 automatic pole top switches • Replace 1 manual pole top switches • Rebuild 3.8 miles of distribution under build

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3				
Benefits:	• Reduce wire outage events and durations. • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3			
Approximate Construction Schedule:	2020: Engineering 2021-2024: Design & Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 19,274,352			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$10,231,512	\$2,230,330	\$ 0
	Material	\$3,521,606	\$ 29,112	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$13,753,118	\$2,259,442	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4
Purpose and Necessity:	Reliability: • Tie 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing subtransmission lines. Lightning causes phase to phase faults, due to lack of lightning protection, leading to breaker operations. • Tie 4105 pole inspection data has shown that a high number of wood poles are deteriorated and require replacement. Sections of conductor from this tie line have been evaluated. It has been determined that the steel core is deteriorated, and the remaining tensile strength is greatly reduced. The conductor has been determined to be at the end of its life based on this evaluation. • The existing Tie 4105 is built in deep right-of-way, which contributes to frequent outages from tree interference as well as longer outage duration due to the line not being truck accessible. There are 3,453 customers directly impacted by the reliability of Tie 4105.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 15

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4
Scope:	• Reconnector 7.1 miles of overhead conductor • Replace 1 manual pole top switches • Rebuild 7.1 miles of distribution under build

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4				
Benefits:	• Reduce wire outage events and durations. • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4			
Approximate Construction Schedule:	2023: Engineering 2024-2025: Design & Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 22,110,690			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5
Purpose and Necessity:	Reliability: • Tie 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing subtransmission lines. Lightning causes phase to phase faults, due to lack of lightning protection, leading to breaker operations. • Tie 4105 pole inspection data has shown that a high number of wood poles are deteriorated and require replacement. Sections of conductor from this tie line have been evaluated. It has been determined that the steel core is deteriorated, and the remaining tensile strength is greatly reduced. The conductor has been determined to be at the end of its life based on this evaluation. • The existing Tie 4105 is built in deep right-of-way, which contributes to frequent outages from tree interference as well as longer outage duration due to the line not being truck accessible. There are 3,453 customers directly impacted by the reliability of Tie 4105.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 69

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5
Scope:	• Reconductor 6.3 miles of overhead conductor

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5				
Benefits:	• Reduce wire outage events and durations • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5			
Approximate Construction Schedule:	2024: Engineering 2025-2026: Design & Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 8,621,923			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 7504
Purpose and Necessity:	Reliability: Customer complaints and escalations have been received due to frequent outages on Tie 7504. Capacity: • Tie 7504 is in violation of the Subtransmission Planning Criteria and is outside subtransmission voltage limits are 92%-105% of the nominal voltage in emergency conditions of a single contingency event (N-1). • Cass City Substation and Proctor Substation have low voltage upon the contingency event of the Tie 7504 breaker operation at Arrowhead Station (Cass City will be at 86% of nominal voltage and Proctor will be at 91% of nominal voltage). Operability: 7 MVA of load is automatically shed on Tie 7504 to prevent low voltage.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 67

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 7504
Scope:	• Replace 12.2 miles of Subtransmission overhead conductor • Install 4 miles of new Subtransmission overhead conductor • Replace 3 pole top switches • Install 1 capacitor • Replace 2 breakers • Replace 2 relay panels • Replace 2 disconnects

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 7504				
Benefits:	• Eliminate customer low voltage events • Prevent customer load shed for a single contingency event • Improve system shutdown capability and operability • Improve customer reliability and power quality				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 7504			
Approximate Construction Schedule:	2022-2023: Engineering 2024-2025: Design 2026-2029: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 38,318,301			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$271,825	\$500,000	\$1,500,000
	Material	\$2,990,886	\$ 0	\$500,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,262,711	\$500,000	\$2,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 810
Purpose and Necessity:	Capacity: • Tie 810 experiences low voltages in multiple single contingency scenarios, which violates the Subtransmission planning criteria. The criteria states that for emergency conditions of a single contingency event (N-1), the Subtransmission voltage limits are 92%-105% of the nominal voltage. There are 30 single contingency scenarios which result in voltage violations below the minimum voltage criteria (as low 87% of nominal voltage). • Tie 810 also experiences overloads in multiple single contingency scenarios. There are 21 unique thermal violations on Tie 810 for single contingency events. Six of these exceed 100% of the equipment's summer emergency rating. Operability: Load will automatically be shed at various substations to prevent this equipment overload.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 66

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 810
Scope:	• Build a new subtransmission voltage station (Gramer Station) • Reconfigure Tie 810 into three separate circuits (Tie 9505, Tie 9514 and Trunk 4938) • Install 11 miles of new overhead conductor • Rebuild 16 miles of overhead lines • Decommission and remove 5 miles of overhead lines

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 810				
Benefits:	• Provide additional capacity to serve existing and new customer load • Reduce risk of thermal overload to equipment and the potential to shed customer load • Improve system shutdown capability and operability to perform regular maintenance work • Improve customer reliability with new overhead lines built along the road and improve power quality with voltage changes				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Tie 810			
Approximate Construction Schedule:	2023-2024: Design and Construction 2026: Construction			
Budget Basis:	Project Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 83,350,270			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$14,831,664	\$8,387,286	\$10,639,715
	Material	\$6,938,982	\$4,612,714	\$5,141,641
	Other	\$ 0	\$ 0	\$138,644
	Total	\$21,770,646	\$13,000,000	\$15,920,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program
Purpose and Necessity:	Reliability: Several subtransmission and distribution transformers require the installation of high side protection, either a circuit switcher or breaker, to mitigate observed NERC reportable system issues during simulated contingency conditions that may result in the loss of service to 100+ MVA of customer load. These issues were discovered during annual studies performed by ITC and are required to be mitigated by NERC TPL-001-4 standards.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 5

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program
Scope:	• Install high side switching devices, circuit switches or breakers on 22 subtransmission and distribution transformers at 16 different stations • Replace or relocate ten of those transformers due to space constraints

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program				
Benefits:	• DTE Transformers will be in compliance with NERC TPL-001-4 criteria • Mitigate the impact of potential DTE equipment failures impacting the ITC Bulk Electric System • Improve Bulk Electric System reliability and resiliency to widespread system outage of 100+ MVA of customer load • Increase DTE operational flexibility by allowing remote operation of protective devices at the transformers				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program			
Approximate Construction Schedule:	• Troy Trf 101 Complete • Newburgh Trf 105: Design in 2023 & Construction in 2024 • Sunset Trf 1: Design in 2023-2024 & Construction in 2024 • Sunset Trf 2: Design in 2023-2024 & Construction in 2025 • Chestnut Trf 3: Design & Construction in 2024 • Chestnut Trf 103: Design in 2024-2025 & Construction in 2026 • Sunset Trf 103: Design in 2023-2024; Construction in 2025 • Sunset Trf 101: Design in 2023-2024; Construction in 2025 • Hines Trf 102: Design in 2024-2025; Construction in 2026 • Wixom Trf 1: Design in 2028; Construction in 2029	Remaining locations, scope & schedule to be defined in future years: • Nburg T101 - defining in 2024 • Hancock T101 - defining in 2024 • Bunce T101 - defining in 2024 • Bunce T102 - defining in 2024 • Neast T3 • Wabash T101 • Wabash T102 • Pontiac T1 • Spokane T2 • Wayne T3 • Waterman T2		
Budget Basis:				
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,878,495	\$4,140,747	\$4,136,324
	Material	\$598,326	\$603,823	\$600,002
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,476,821	\$4,744,570	\$4,736,326

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2237-ST
Purpose and Necessity:	Capacity: Trunk 2237 is loaded to 100% of the equipment's summer normal rating and 110% of the equipment's summer emergency rating, violating the Subtransmission planning criteria. Operability: There is an Emergency Load Control scheme at Six Mile Substation that will automatically shed load (10.3 MVA) to prevent from overloading equipment on Trunk 2237 and protect the equipment from any permanent damage
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 9

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2237-ST
Scope:	• Install 4,400 feet of cable • Install a new cable pole • Install 15 ft of conduit to new cable pole

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2237-ST				
Benefits:	• Alleviate the Summer Normal and Summer Emergency overloads • Remove the Automatic throwover blocking schemes and the potential for 10.3 MVA of customer load shed during a contingency outage event on TRUNK 2250AC-BC • Improve operability and enable load transfers during planned work and trouble events				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2237-ST			
Approximate Construction Schedule:	2022-2023: Construction			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 1,535,072			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$176,132	\$ 0	\$ 0
	Material	\$16,773	\$ 0	\$ 0
	Other	\$13,782	\$ 0	\$ 0
	Total	\$206,686	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2255
Purpose and Necessity:	Capacity: Trunk 2255 is loaded to 110% of the Summer Emergency rating, exceeding the Subtransmission planning criteria. Operability: Approximately 11 MVA of load will automatically be shed at Glendale and Villa substations to prevent this equipment overload.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 8

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2255
Scope:	A new underground cable will be installed to distribute the load: • Break down an existing branch joint in Manhole 15434 and install one new straight joint • Remove 4,765 feet of existing underground cable on Trunk 2255 from Manhole 15434 to Villa Transformer 2 • Install 1 cable pole and termination • Install a total of 1,116 feet of conduit • Install 3 new manholes • Install 6,687 feet of underground cable from cable pole to Villa Transformer 2 utilizing the existing conduit • Contingency plan: temporary overline feed installed from Trunk 2247

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2255				
Benefits:	• Alleviate the Sumer Normal and Summer Emergency overloads • Remove the automatic throwover blocking schemes and the potential for 11 MVA of customer load shed during a contingency outage event on Trunk 2276 • Improve operability and enable load transfers during planned work and trouble events • Replace aging cable with new cable reducing the risk of outages				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2255			
Approximate Construction Schedule:	2022 Construction 2023 Construction/Project close out			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 3,403,341			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$546,467	\$ 0	\$ 0
	Material	\$99,531	\$ 0	\$ 0
	Other	\$52,135	\$ 0	\$ 0
	Total	\$698,133	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2308
Purpose and Necessity:	Capacity: Trunk 2308 is loaded to 99% of its summer emergency rating, exceeding the Subtransmission planning criteria. Operability: There is an Emergency Load Control scheme at BENSX substation that will automatically shed load (5.4 MVA) to protect from overloading equipment and causing permanent damage for a single contingency event.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 70

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2308
Scope:	• Reconductor 3.3 miles of overhead conductor • Replace pole top switch • Distribution underbuild to be reconducted as well as associated equipment upgrades: ○ Replace 2 reclosers ○ Replace 30 overhead distribution transformers ○ Replace 1 capacitor ○ Replace 7 overhead switches ○ Replace 6 fuses ○ Replace 36 cable poles • Install 3600 feet of conduit • Install 7200 feet of cables (including 144 straight joints)

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2308				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • 10.8 MVA of capacity added to Trunk 2308 • Improve system shutdown capability and operability • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 2308			
Approximate Construction Schedule:	2023-2024: Design 2024-2025: Construction 2025: Closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 11,248,407			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$644,056	\$824,075	\$3,969,598
	Material	\$2,580,443	\$145,925	\$ 31,161
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,224,499	\$970,000	\$4,000,759

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 3509
Purpose and Necessity:	Capacity: Trunk 3509 is loaded to 100% of the equipment's summer normal rating and 109% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: There is an Emergency Load Control scheme at PATON substation that will automatically shed load (4.1 MVA) to prevent from overloading equipment on Trunk 3509 and protect the equipment from any permanent damage.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 18

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 3509
Scope:	• Install 1 breaker • Install 2 disconnects • Install 1 relay panel • Install 733 feet of conduit • Replace 6,225 feet of cable

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 3509				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • 1.5 MVA of capacity created on Trunk 3509 • Improve system shutdown capability and operability.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 3509			
Approximate Construction Schedule:	2021: Engineering 2022: Design 2023-2024: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 6,080,116			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,260,364	\$1,832,390	\$ 0
	Material	\$ 23,158	\$772,401	\$ 0
	Other	\$ 0	\$1,048,311	\$ 0
	Total	\$2,283,522	\$3,653,102	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4217
Purpose and Necessity:	Capacity: Trunk 4217 is loaded to 123% of the equipment's summer normal rating and 116% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria. Operability: There is an Emergency Load Control scheme at Grosse Pointe and Vernier substations that will automatically shed load (3.5MVA) to protect from overloading equipment and causing damage for a single contingency event.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 17

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4217
Scope:	• Install a new position at Erin station (1 breaker and 2 disconnects). • Install 2.1 miles of new underground cable from the new station position at Erin station to manhole 14768. • Remove 2.1 miles of existing underground cable. • Replace Vernier Transformer 3 secondary breaker and cable terminations.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4217				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • New equipment ratings lower the percent of capacity utilized by the current system loading. • Improve system shutdown capability and operability. • Reduced substation outage risk by replacing aging infrastructure. • Investment in an EJ community				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4217			
Approximate Construction Schedule:	2021-2022: Design 2023-2025: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 7,202,159			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$817,345	\$250,555	\$ 0
	Material	\$1,103,904	\$ 98,112	\$ 0
	Other	\$ 0	\$1,916,118	\$2,359,546
	Total	\$1,921,249	\$2,264,785	\$2,359,546

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4245
Purpose and Necessity:	Reliability: The conduit crossing at I-94 and 9 Mile Road is damaged causing cable to become stuck in the ducts. Shores substation is at risk of losing its subtransmission feeds if cable failures occur.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 75

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4245
Scope:	• Install 3,400 feet of conduit, including 12 new manholes • Install 3.3 miles of cable • Remove 1.3 miles of cable

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4245				
Benefits:	• Eliminate risk of customers experiencing a long outage due to cable failure in a duct bank with no spare conduit. • Improve system shutdown capability and operability. • Increase duct capacity • Provides the option to reroute the other circuits in the existing duct in case of another failure. • Improves circuit ratings. • Relocating the circuits removes us from interfering with any future bridge work that MDOT has planned. • Eliminates the possibility of flattening SHORS Substation; impacting 5,600 customers powers and ~21 MVA of load. • Significantly less contingency planning would be needed • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4245			
Approximate Construction Schedule:	2022-2023: Engineering 2024: Design 2025-2026: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 12,744,727			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$283,405	\$494,523	\$878,948
	Material	\$0	\$0	\$491,598
	Other	\$420,000	\$105,477	\$329,454
	Total	\$703,405	\$600,000	\$1,700,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4266
Purpose and Necessity:	Capacity: Trunk 4266 is loaded to 108% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria. Operability: There is an Emergency Load Control scheme at SAVOY substation that will automatically shed 6.4 MVA of load to protect from overloading equipment and causing permanent damage for this single contingency event.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 19

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4266
Scope:	• Replace 3.94 miles of underground cable

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4266				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • 25.5 MVA capacity added to Trunk 4266 • Improve system shutdown capability and operability. • Investment in EJ communities				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x				

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4266			
Approximate Construction Schedule:	2022-2023: Engineering 2023-2024: Design 2025: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 8,897,277			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4911
Purpose and Necessity:	Capacity: Trunk 4911 is in violation of the Subtransmission Planning Criteria and has thermal overloads on the equipment under normal conditions and for several single contingency events including the following: • Trunk 4911 is 118% of the equipment's Summer Normal rating • Trunk 4911 is at 130% of the equipment's Summer Emergency rating upon the N-1 contingency event of an outage on Trunk 4971. • Trunk 4911 is at 117% of the Summer Emergency rating upon the N-1 contingency event of an outage on Trunk 4962. There are also voltage violations at Ira, New Baltimore and Cotton Substations for single contingency (N-1) events. This is a violation of the Subtransmission Planning Criteria and that states the subtransmission voltage should be 92%-105% of nominal voltage. These violations include: • Low voltages at Ira - 87.8%, New Baltimore - 88.1%, Cotton - 89.4% upon single contingency loss of Trunk 4971. • Low voltages at Ira - 89.69%, New Baltimore - 91.76%, Cotton - 89.96% upon single contingency loss of Trunk 7913. • Four other single contingency events result in low voltages for the same substations in the range of 90% - 91.7%. Operability: There are emergency load control schemes at New Baltimore and Chesterfield substations that will automatically shed load (12.8 and 9.1 MVA respectively) to prevent overloading the equipment on Trunk 4911.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 76

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4911
Scope:	• Trunk 4911: • Reconductor 12.4 miles of overhead • Replace seven pole top switches • Install cable terminations • Install 240 ft of conduit • Replace 220 ft of cable • Upgrade relaying • Trunk 4950: • Expand Victor Bus 1 with new position including breaker, disconnect switches, and relay panel • Install 0.7 miles of conduit including nine new manholes • Install 0.7 miles of 40 kV cables • Construct 3.6 miles of 40 kV overhead including new cable pole • Trunk 4962: • Relocate 1 mile of 40 kV overhead

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4911				
Benefits:	• Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event. • Alleviate voltage violations, and the possibility of shedding customer load during a single contingency event. • New equipment ratings lower the percent of capacity utilized by the current system loading. • Improve system shutdown capability and operability. • Replace 3/0 ACSR wire known for bad condition, that is prone to failures that result in wire down events.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:				x	

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 4911			
Approximate Construction Schedule:	2022: Engineering 2023: Engineering & Design 2024-2026: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 26,471,265			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7106
Purpose and Necessity:	Trunk 7106 is in violation of the Subtransmission Planning Criteria and has a thermal overload. Trunk 7106 is loaded to 134% of the equipment's summer normal (N-0) rating with no capacity for new load. Trunk 7106 is loaded to 126% of the equipment's summer emergency (N-1) rating for the single contingency event of an outage on Trunk 2237 or Trunk 7151. Farmington (FRMTN) Substation automatic throwover has been placed on manual blocking to prevent equipment failure on Trunk 7106 due to overloads. 12.7 MVA of customer load at FRMTN substation will be dropped in the event of an outage of Trunk 7151. This is a violation of the Subtransmission Planning Criteria.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 7

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7106
Scope:	Reconfigure 40 kV Trunk 7106 into two circuits: Trunk 7106 and Trunk 7187: • TRUNK 7106 will serve Farmington substation Transformer 4 utilizing the existing cable • Create new Trunk 7187 at Southfield station Position RC to serve Subtransmission Distribution Facility 38, West Service Center Transformer 1 and Indian Transformer 2: • Install 40 kV breaker and two 40 kV disconnects at Southfield station Position RC • Install 2.3 miles of 40 kV 650-1Cx3 EPR cable for Trunk 7187 from Southfield station Position RC to the overhead cable pole • Install a manual Pole Top Switch on Trunk 7187

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7106				
Benefits:	- Alleviate thermal loading violations, and the possibility of shedding customer load during a single contingency event - Eliminate automatic throwover blocking schemes that can result in customer outages during a single contingency event, improve operability and enable load transfers during planned and trouble events				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7106			
Approximate Construction Schedule:	2022: Construction			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 2,667,402			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	-\$636	\$ 0	\$ 0
	Material	-\$89,041	\$ 0	\$ 0
	Other	-\$348	\$ 0	\$ 0
	Total	\$- 90,025	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7333
Purpose and Necessity:	Capacity: Trunk 7333 is loaded to 129% of the summer normal rating and 126% of the summer emergency rating, exceeding the Subtransmission planning criteria. Operability: Load (~12MVA) will automatically be shed at Brazil & Kenney substations to prevent this equipment overload.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 10

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7333
Scope:	• Reconfigure Trunk 7333T into two separate trunk lines - Trunk 7333 and Trunk 7370 • Rebuild Trunk 7333 underground cable joint with a straight joint in Manhole 17429 • For Trunk 7370, install 16,391 feet of underground cable from Chestnut station Position SB to Manhole 17429 via existing conduit • Install a 40 kV breaker and two 40 kV disconnects at Position SB in Chestnut station

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7333				
Benefits:	• Alleviate Summer Normal and Summer Emergency overloads • Remove the automatic throwover blocking schemes and the potential for 12 MVA of customer load shed during a contingency outage event on Trunk 7315 • Improve operability and enable load transfers during planned work and trouble events				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Subtransmission Redesign & Rebuild: Trunk 7333			
Approximate Construction Schedule:	2022 Construction completion 12/29/22 2023 Closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,699,265			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$127,709	\$ 0	\$ 0
	Material	\$ 39,854	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$167,563	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Brown City
Purpose and Necessity:	Capacity, operability and load relief are the main drivers for this project which will ultimately construct a new 13.2 kV substation, rebuild a substation and decommission a 4.8 kV substation. Other drivers for this project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. Capacity: • MARLT substation is at 112% of its firm rating and 92% of emergency rating. • MARLT DC 8291 is at 112% of its day to day rating. • BRCTY substation is at 104% of its firm rating. • BRCTY DC 0305 is at 100% of its day to day rating. • TCOMA substation is at 105% of its firm rating. • TCOMA DC 8311 is at 90% of its day to day rating. SHAW substation is at 126% of its firm and 100% of its emergency rating. Operability: BRCTY substation is 4.8 kV and surrounded by TCOMA substation, which is 13.2 kV, limiting the jumpering for BRCTY substation.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 92

(a)

(b)

Program:	System Loading: Brown City
Scope:	• Install (1) new 120-13.2 kV Substation • Rebuild (1) existing 40-13.2 kV Substation • Rebuild (1) existing 40-4.8 kV Substation • Pre-convert and Convert (56) miles of overhead conductor • Reconductor (5) miles of overhead conductor • Install (1) mile of new overhead conductor • Decommission (1) 40-4.8 kV substations

(a)

(b)

Program:	System Loading: Brown City				
Benefits:	• Provide capacity to allow load growth • Decommission aging infrastructure and reduce major event risk • Enhance safety, reliability, and power quality for upgraded circuits • Provide capacity for potential new developments in areas surrounding BRCTY, TCOMA and SHAW Substations • Relief for substation and circuit overloads • Convert existing 4.8 kV distribution circuits to 13.2 kV • Provide jumpering options when currently there is limited/none jumpering options in the area				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:			x	x	x

(a)

(b)

Program:	System Loading: Brown City			
Approximate Construction Schedule:	2022: Engineering Begins 2023-2027: Overhead Pre Conversion work for MARLT 8281 2026: MARLT DC0315 and 0316 Pre Conversion work 2027-2028: BRCYT, TCOMA, and SHAW Pre Conversion 2025: Construction of New BENET Substation 2026: Decommission MARLT TRF3, Install MARLT TRF4 (1/2 of the Class R) 2027: Decommission MARLT TRF1 & 2, Install MARLT TRF5, Finalize Class 'R' at MARLT 2028: Transfer BRCTY, TCOMA, and SHAW load to BENET, Decommission BRCTY			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 84,509,290			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,715,903	\$4,703,154	\$4,597,919
	Material	\$769,248	\$2,688,485	\$2,036,120
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,485,151	\$7,391,639	\$6,634,039

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Carleton
Purpose and Necessity:	This project upgrades Carleton substation to address capacity and loading concerns. Drivers for the project include the following: Capacity: • Carleton substation is a two circuit, two transformer 4.8 kV substation. • Transformer 2 is at 112% of its day to day rating. • CARLT DC 312 is at 124% of its day to day rating. Operability: Limited jumpering options due to substation and circuit loading
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 58

(a)

(b)

Program:	System Loading: Carleton
Scope:	• Reroute 4.8 kV and 40 kV overhead on the substation property • Expand substation fence on the north side • Install new control center • Replace both transformers with 5/6.3MVA transformers and upgrade associated equipment • Re-establish J1 point between the two circuits

(a)

(b)

Program:	System Loading: Carleton				
Benefits:	• Reduce equipment risk by alleviating the day to day overloads on the circuit, bus, and transformer • Re-establish the J1 point between the two circuits				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	System Loading: Carleton			
Approximate Construction Schedule:	2023 - Energize new substation and remove decommissioned equipment and complete overhead construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,201,354			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$119,297	\$ 0	\$ 0
	Material	\$13,895	\$ 0	\$ 0
	Other	\$53,810	\$ 0	\$ 0
	Total	\$187,002	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Cody
Purpose and Necessity:	Load relief and capacity are the main drivers for this project which will expand CODY substation. Other drivers for the project include the following: Safety: Improve safety risk associated from downed wires on ISO-down 4.8 kV ungrounded delta circuits. Capacity: • Cody (CODY) substation has two transformers and four load carrying circuits. ○ DC 9537 has a summer peak of 14.7MVA and is 80% of its day-to-day rating. It is projected to be at 15.5MVA in 2023/2024 with the addition of a new residential development. ○ DC 8824 has a summer peak of 16.8MVA. ○ A third circuit, DC 8939 has a summer peak of 5.7MVA but is projected to be at 8.1MVA in 2024/2025 with the addition of a new residential development • The substation is 104% of its firm rating. Operability: For this substation configuration, upon the loss of a transformer, the load of each circuit on that transformer should be able to transfer to a circuit on the other transformer. Due to the high loads on these circuits, that is not possible. There are little to no jumpering options outside of the substation due to overloaded circuits and ISO down pockets limiting load transfers. Other: All of the CODY circuits have customers larger than the DTE average. Every CODY circuit has overhead miles larger than the DTE & the 13.2 kV circuit average. Multiple residential methods of services have been received in CODY territory and Lyon Twp has mentioned a couple more developments in the near future.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 95

(a)

(b)

Program:	System Loading: Cody
Scope:	• Expand 120-13.2 kV Substation to increase capacity and install more circuits • Extend fence line to be able to accommodate expansion • Install (12) miles of cable (including throwover cable) • Install (5.6) miles of system conduit • Rebuild or replace (7.5) miles of overhead conductor • Underground beginning of (4) existing circuits • Establish (4) new circuits and underground the beginning of the circuit • Establish throw over circuit to ensure backup feed in case of cable failure • Convert (2.9) miles of 4.8 kV to 13.2 kV • Circuit phase balancing for better voltage

(a)

(b)

Program:	System Loading: Cody				
Benefits:	• Current firm is 40MVA, new firm is 60MVA. Capacity increase of 50%. • Balance phasing of circuits to avoid breaker operation caused by high-phase load • Relieve heavy loaded circuits to avoid circuit ratings • Less OH Miles per circuit • More positions for future load growth • Should support area for decades since it will be mostly residential load growth in the area				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Cody			
Approximate Construction Schedule:	2023 - 2025: Engineering and design 2024 - 2030: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 71,600,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$269,653	\$1,124,300	\$7,026,874
	Material	\$100,394	\$418,585	\$2,616,157
	Other	\$13,699	\$57,115	\$356,969
	Total	\$383,745	\$1,600,000	\$10,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Diamond
Purpose and Necessity:	Diamond substation is a two transformer, four circuit substation and is at 137% of its firm rating. This project will upgrade one of the substation transformers at the substation. Drivers for the project include the following: Reliability: In summer 2018, load shedding was implemented at the substation due to equipment overloads. SAIFI 5 year average is 1.97 and SAIDI 5 year average is 566. Capacity: The substation is currently at 137% of firm rating. Operability: Transformer #1 was replaced during an emergency failure event in March 2019; firm rating is now limited by smaller sized Transformer #2.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 104

(a)

(b)

Program:	System Loading: Diamond
Scope:	• Replace substation transformer with a larger unit

(a)

(b)

Program:	System Loading: Diamond				
Benefits:	- Replacement of Transformer 2 would increase the firm rating capacity by 80% - Eliminate 8.6MVA of stranded load for DIMND Substation by reducing firm below 100%				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	System Loading: Diamond			
Approximate Construction Schedule:	2024: Engineering 2025: Substation design and order major equipment (transformer) 2026-2027: Complete Substation Design, receive major equipment and complete transformer replacement at the substation			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 3,983,877			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 20,638	\$ 230,507
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 20,638	\$230,507

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Disco
Purpose and Necessity:	This project will install two new circuits out of Bronco substation to relieve load at Disco substation and circuits. Drivers for the project include the following: Reliability: In 2022, the SAIDI and CAIDI for all DISCO circuits were above the DTE system average due to several day outages. Capacity: In 2022 DISCO was at 111% of FIRM and in 2023 DISCO was at 109% of FIRM. There are currently two transformers and four load carrying circuits at DISCO substation. There are no spare positions at DISCO to build a new circuit. Operability: DISCO circuits have limited jumpering options due to neighboring circuits being overloaded. In 2023, diesel generators cannot support the substation overload due to high phase imbalance on circuits. Approximately ~1.9 MVA of load had to be shed, leaving customers without power when there is a substation failure, to bring DISCO below 90% of FIRM in the 2023 addendum.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 107

(a)

(b)

Program:	System Loading: Disco
Scope:	• Install (1) mile of new system conduit • Install (3.5) miles of new system cable • Install Neutral Cable (1) mile • Build (2) Distribution Circuits on BRONC • Installing (0.2 miles) of new overhead conductor • Install and remove overhead equipment such as PTS's, Reclosers, Disconnect Switches, and fuses for better reliability and loop schemes. • Replace/ Install poles to strengthen the grid

(a)

(b)

Program:	System Loading: Disco				
Benefits:	• Reduce loading on DISCO from 111% to 75% of firm rating • Create more loop schemes and more jumpering points between BRONC and DISCO circuits • Move 8.7 MVA from DISCO to BRONC				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	System Loading: Disco			
Approximate Construction Schedule:	2023: Engineering 2024: Design 2025: Conduit / Substation 2026: Cable / OH Load Transfers			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 5,146,388			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$69,127	\$384,796	\$2,190,124
	Material	\$2,901	\$16,147	\$91,903
	Other	\$2,836	\$15,784	\$89,839
	Total	\$ 74,863	\$416,728	\$2,371,867

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Globe
Purpose and Necessity:	This project will decommission the existing Globe substation and install a Subtransmission Distribution Facility (STDF) with a larger transformer to provide capacity in the area. Drivers for the project include the following: • Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. • Capacity: GLOBE is at 2.4 MVA, or 75% of its DD rating. High load growth is due to Vassar Township issuing permits for indoor agricultural centers • Operability: No jumpering option available between Globe and nearby Sheridan substation • Other: GLOBE transformer size needs to be increased to provide load relief opportunities for future SHRDN substation.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 15, Line 63

(a)

(b)

Program:	System Loading: Globe
Scope:	• Decommission (1) existing substation • Install (1) new STDF • Install new overhead protection devices • Relocate (1) portable substation location • Reconfigure 40 kV overhead

(a)

(b)

Program:	System Loading: Globe				
Benefits:	• Provide sufficient capacity to serve existing and new customer load • Reduce substation outage risk by replacing aging infrastructure • Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:				x	x

(a)

(b)

Program:	System Loading: Globe			
Approximate Construction Schedule:	2024 Substation Design, Engineering 2025 - Construction			
Budget Basis:	Based on PM Estimates for Rate Case from 2021			
Total Cost: \1	The estimated project cost for this investment is \$ 2,900,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$200,000	\$1,896,433
	Material	\$ 0	\$ 0	\$803,567
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$200,000	\$2,700,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Goodison
Purpose and Necessity:	Drivers for this project include the following: Reliability: Goodison (GODSN) SAIDI and SAIFI usually is above the DTE system average. Capacity: GODSN is at 129% of its firm rating. Operability: Jumpering options outside of GODSN are not available during summer peak due to TINKN and JEWEL substations exceeding their firm ratings and because of the heavy loading on neighboring circuits. Overloads and low voltage occur when load is transferred to neighboring substations.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 102

(a)

(b)

Program:	System Loading: Goodison
Scope:	This is preliminary engineering scope, subject to revision during detail engineering phase Scope changes will occur based on property location acquired for new substation. • Purchase new property • Installing (1) new 40-13.2 kV substation • Rebuilding or replacing (1.5) miles of overhead conductor • Install (2.0) miles of new overhead • Installing (0.5) miles of system conduit • Installing (1.0) miles of system cable

(a)

(b)

Program:	System Loading: Goodison				
Benefits:	- GODSN substation will be below firm - Creates more jumpering between GODSN, the new substation, and the other neighboring substations - GODSN substation firm is 19MVA. New substation firm will be 19MVA as well. Capacity increase of 100%.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Goodison			
Approximate Construction Schedule:	2025: Property purchase 2026: Engineering and design 2027 - 2028: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 18,125,405			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 78,880
	Total	\$ 0	\$ 0	\$ 78,880

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Grenada
Purpose and Necessity:	Grenada substation is located in Ann Arbor. There are four substations serving the general area: Grenada, Price, Prospect and Wolverine. Drivers for the project include the following: Reliability: GRENA has a 3-year average SAIDI of 1,487. Capacity: • Prospect and Wolverine substations are either near or exceed 100% of their firm rating. • For the loss of any one of these substations, the stranded load could range from 4% to 30% of total load • For the loss of a single transformer at any one of these four substations, the stranded load could be as high as 9% of total load. • There is continued load growth in the area and the existing substations and circuits are unable to support Ann Arbor's electrification goals. Operability: • There is a lack of jumpering capability for Grenada, Prospect and Price substations. • The use of distributed generation would be required in the case of any failure at the substations mentioned above.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 98

(a)

(b)

Program:	System Loading: Grenada
Scope:	• Reconductor (17) miles of overhead conductor • Replace (3) miles of underground cable • Replace (61) overhead transformers • Replace (17) underground transformers • Install (3) miles of system cable • Install (2) miles of system conduit • Decommission (1) 40-4.8 kV substation • Decommission (1) 40-13.2 kV substation • Install (1) 40-13.2 kV substation • Establish (4) load carrying circuits • Install (4) transformers • Install (1) switchgear • Install and replace poles • Install sectionalizing and operating devices

(a)

(b)

Program:	System Loading: Grenada				
Benefits:	• Capacity increase of 77% • 88% SAIDI improvement projection • Bring substation firm below 100%, eliminating the risk of stranded load • Supports GRENA Class 'F', PROSP, and PRICE decommissioning				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Grenada			
Approximate Construction Schedule:	2022: Engineering and Initial Design 2023-2028: Detailed design and construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 67,750,600			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$3,521,168	\$5,859,039	\$3,683,498
	Material	\$ 0	\$639,232	\$8,316,502
	Other	\$ 0	\$ 36,792	\$ 0
	Total	\$3,521,168	\$6,535,063	\$12,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Jewell
Purpose and Necessity:	This project will construct a new 13.2 kV substation to relieve Jewell (JEWEL) substation and decommission an aging 4.8 kV Washington (WSHTN) substation. Drivers for the project include the following: Reliability: The circuits have been close to or exceeded the DTE average for SAIDI and CAIDI. Capacity: - Jewell Substation serves seven load carrying circuits. Two circuits exceeded their circuit day-to-day rating, with one circuit reaching as much as 15.3 MVA. There are two additional circuits that are between 92% and 99% of their day-to-day ratings. - The location of the load centers for the two circuits are located such that transferring load to adjacent circuits is not possible without causing loading issues on adjacent circuits. There is evidence of steady growth and new business across the Jewell Substation area. - In Summer 2022, Jewell substation was at 107% of its firm rating. - Jewell Substation has four spare circuit positions, but Jewell substation does not have enough capacity to utilize these spare positions. In addition, there are physical constraints that do not facilitate a substation expansion. Operability: The closest substation to Jewell is Washington Substation. Load transfers to Washington are not possible because it is a 40-4.8 kV substation. Converting Washington substation property has physical constraints prohibiting expansion. Furthermore, Washington is served from overloaded 40 kV Tie 6907. Other: There has been several residential developments on JEWEL within the past couple years. The area has open land, so we expect more businesses and residential developments to come. Every circuit on JEWEL has more customers than the DTE average per circuit along with the 13.2 kV average per circuit. 3 JEWEL circuits have overhead miles more than the DTE and 13.2 kV average per circuit.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 100

(a)

(b)

Program:	System Loading: Jewell
Scope:	This is preliminary scope and will be refined during detailed engineering. • Property Acquisition • Build 120-13.2 kV Class A substation with 3-24/32/40 MVA transformers and 2-12 position switchgear • Establish five load carrying circuits and a throw over circuit to provide load relief to JEWEL Substation • Install about 7 miles of conduit and 52 miles of system cable • Convert about 19 miles of overhead • Convert about 17 miles of URD • Decommission 4.8 kV WSHTN substation

(a)

(b)

Program:	System Loading: Jewell				
Benefits:	- The new substation will add approximately 120 MVA of capacity - Provide load relief to Jewell substation - Converting Washington circuits from 4.8 kV to 13.2 kV and transferring them to the new substation will improve reliability, operability and create capacity on 40 kV Tie 6907 - Improve jumpering and implement loop schemes				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	System Loading: Jewell			
Approximate Construction Schedule:	2023-2024: Property purchase and Conceptual engineering 2025: Engineering 2026: Design 2027: Substation/Conduit/Pre-Conversion/Reconductoring 2028: Cable/Pre-Conversion/Reconductoring 2029: Conversion/Load Transfers/ Remaining OH Work 2030: Decommission WSHTN substation & Closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 46,158,015			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,134,343	\$530,339	\$326,306
	Material	\$58,533	\$27,366	\$16,838
	Other	\$72,423	\$33,860	\$20,833
	Total	\$1,265,299	\$591,564	\$363,977

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Kings Point
Purpose and Necessity:	This project will construct a new 13.2 kV substation to provide capacity in the area. Drivers for the project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits Capacity: • Boyne substation is a 120 kV-13.2 kV substation and is 114% of its firm rating. BOYNE DC 8512 is 109% of day-to-day rating and BOYNE DC 8710 is 93% of its day-to-day rating. • Golf Substation is a 120 kV-13.2 kV substation and is at 93% of its firm rating. Two circuits at Golf substation exceed their day-to-day ratings while three others exceed 90% of their day-to-day ratings. • Nearby Omega substation is a 40 kV-13.2 kV substation which is 5.4MVA of its blocking limit. The loss of either transformer at Omega substation results in 5.8MA of stranded load. • The subtransmission lines are overloaded in the area (Trunk 7909 and Trunk 6759). The current infrastructure is unable to support new load growth in the area. Operability: Omega and surrounding substations high loading limits jumpering options
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 110

(a)

(b)

Program:	System Loading: Kings Point
Scope:	• Procure (1) new property • Install (1) new substation • Install (3) miles of new conduit • Install (14) miles of new cable • Reconductor (5) miles of existing overhead conductor • Convert (3) miles of existing overhead conductor • Install (4) new cable poles

(a)

(b)

Program:	System Loading: Kings Point				
Benefits:	• Relieve ~48MVA from BOYNE, GOLF, SUTTN, and OMEGA to bring their firms to below 90%. • Provides additional capacity for load growth in the area • Sets up relief for CHEST substation in the future • Convert two 4.8 kV circuits to 13.2 kV and decommission the associated high risk system cables with known failures • Increases reliability for the area by reducing circuit exposure and customers affected • Average load for 13.2 kV circuits will be reduced from 8.9MVA to 8MVA, this allow for automatic T.O. via loop schemes • Relieve load on the subtransmission by 13 MVA • Eliminate stranded load at OMEGA • Install 2 new circuits from GOLF and load-transfer will solve the overloads for the two existing circuits				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Kings Point			
Approximate Construction Schedule:	2022: Purchase substation property 2023 - 2024: Engineering & Design 2026 - 2028: Substation Construction 2024 - 2025: ITC Design 2027 - 2028: ITC Construction 2025 - 2027: OH Pre-conversion and conduit 2026 - 2027: Cable 2028: OH Conversion 2028: Substation In Service			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 84,170,796			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$135,404	\$1,000,000	\$2,030,239
	Material	\$ 0	\$ 0	\$2,469,761
	Other	\$ 0	\$ 0	\$ 0
	Total	\$135,404	\$1,000,000	\$4,500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Lark/Spruce
Purpose and Necessity:	This project constructs a new 13.2 kV substation with two new circuits to relieve Spruce substation and reconfigure Spruce circuits. Drivers for this project include the following: Safety: Spruce substation (SPRUC) has equipment that has been designated as high risk. It will be easier to replace this equipment once the substation expansion is completed at LARK (120-40 kV ITC/DTE Station in proximity of Spruce). Reliability: Spruce circuits have frequent outages that have resulted in higher than system average SAIDI and CAIDI minutes. There are sections of circuits that are located in difficult to access areas which are problem areas for downed wires. Capacity: Spruce substation is at 101% of its firm rating. There is limited capacity for load growth in the area. Operability: Spruce circuits have areas that are 13.2 kV islands (adjacent to 4.8 kV) which has led to limited jumpering points and little opportunity for load transfers.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 99

(a)

(b)

Program:	System Loading: Lark/Spruce
Scope:	This is preliminary scope and will be refined during detailed engineering. • Construct a new 120-13.2 kV at existing ITC-DTE LARK Station • Rebuild 2.5mi of overhead subtransmission conductors to 40 kV spec • Rebuild 2.25mi of overhead three-phase conductors to 13.2 kV spec • Rebuild 2.85mi of overhead single-phase conductors to 13.2 kV spec • Rebuild up to 0.4mi of underground residential distribution cables to 13.2 kV spec • Remove 1.0 mi of overhead three-phase conductors (non-accessible wire) • Install 0.7 mi of conduit for circuit exits • Install 0.7 mi of system cable for circuit exits • Install 10 three-phase reclosers • Decommissioning 1 circuit • In-commissioning 3 circuits • Update circuit sectionalizing • Converting sections to 13.2 kV

(a)

(b)

Program:	System Loading: Lark/Spruce				
Benefits:	• Project will increase capacity in the area by approximately 60% • New circuits will improve operability and reliability by creating new jumpering points • Rebuilt circuits and diversified routes will improve reliability by approximately 75% • New circuits will include additional sectionalizing devices and automatic loop schemes to reduce customers affected during large outages • Long term, Lark may facilitate the decommissioning of 4.8 kV King Seeley substation				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x		x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Lark/Spruce			
Approximate Construction Schedule:	2023 - Started Engineering 2024 - Continue Engineering and begin Design 2025 - Complete Design and begin Construction 2026/27 - Construction 2028 - Complete Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 10,696,321			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$756	\$1,350,498	\$2,022,468
	Material	\$0	\$0	\$2,022,468
	Other	\$23,458	\$0	\$0
	Total	\$ 24,213	\$1,350,498	\$4,044,936

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Macomb/Golf
Purpose and Necessity:	This project will expand Macomb substation to provide load relief and capacity for the area. Drivers for the project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits Capacity: • MACMB - 103% of its firm rating. One circuit is at 118% of its day-to-day rating. • HARPR - 93% of its firm rating. • MEDNA - 109% of its firm rating. • BENSJ - approaching its firm rating. • NUNLY - approaching its firm rating.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 97

(a)

(b)

Program:	System Loading: Macomb/Golf
Scope:	• Install (1) transformer at MACMB substation • Install (2) PDC's at MACMB substation • Reconfigure (1) substation • Convert (10) miles of overhead conductor

(a)

(b)

Program:	System Loading: Macomb/Golf				
Benefits:	• Reduces the stranded load • Transfer existing circuits to new PDC's • Moves load from existing Class 'T' equipment to new Class 'A' equipment • Relieves 24 kV system by 21.7 MVA by using existing 120 kV leads • MACMB SUB 112% of firm to 79% of firm				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Macomb/Golf			
Approximate Construction Schedule:	2025 - 2026: Engineering & Design 2026 - 2029: Substation Construction 2028: Substation in Service 2025 - 2027: OH Pre-conversion and conduit 2026 - 2027: Cable 2029: OH Conversion and load transfers			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 32,400,710			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$126,329
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$126,329

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Mayville
Purpose and Necessity:	This project will construct a new Subtransmission Distribution Facility (STDF) to relieve load from MAYVL and CLIFF. Drivers for the project include the following: Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. Reliability: The area has suffered from extensive outage events that lead to a large amount of stranded load for more than 24 hours Capacity: • MAYVL substation is 126% of its firm rating. MAYVL DC 301 is 104% of its DD. • ANDER substation is 80% of its firm rating but only 300kVA of capacity remains until it reaches 100% of its firm. • CLIFF substation is 114% of its firm rating.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 101

(a)

(b)

Program:	System Loading: Mayville
Scope:	• Install (1) new STDF • Reconductor (6) miles of overhead conductor • Install (45) miles of new neutral overhead conductor • Replace (100) overhead transformers • Convert (12) miles of overhead conductor • Install (2) ISO-Down overhead transformers

(a)

(b)

Program:	System Loading: Mayville				
Benefits:	• Provide sufficient capacity to serve existing and new customer load • Reduce substation outage risk by replacing aging infrastructure • Increase jumpering capability and eliminate stranded load associated with the islanded 4.8 kV system • Enhance safety, reliability and power quality for upgraded circuits • Increase protection for the distribution system • Reduce new customer connection timeframe and cost				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Mayville			
Approximate Construction Schedule:	2025: Purchase substation property 2025 - 2026: Engineering & Design 2027 - 2029: Substation Construction 2029: Substation in Service 2026 - 2027: OH Pre-conversion and conduit 2027 - 2028: Cable 2029: OH Conversion			
Budget Basis:	Project Management Estimate - 2021 rate case			
Total Cost: \1	The estimated project cost for this investment is \$ 23,807,625			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$150,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$150,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: New Baltimore/Chesterfield
Purpose and Necessity:	This project will build a new 13.2 kV substation and upgrade the existing New Baltimore (NBALT) substation to provide capacity and load relief to NBALT and Chesterfield (CHEST) substations. Drivers for the project include the following: • Safety: Improve safety risk associated from downed wires on 4.8 kV ungrounded delta circuits. • Reliability: NBALT is over its blocking limit to protect TRUNK 4911 and a loss of transformer 3 will result in 3MVA of stranded load. • Capacity: ○ NBALT substation is at 167% of its firm rating ○ NBALT DC 8434 is at 91% of its DD rating ○ CHEST substation is 101% of its firm rating. ○ CHEST DC 8465 is at 105% of its DD rating ○ CHEST DC 8430 is at 104% of its DD rating ○ CHEST DC 8147 is at 92% of its DD rating ○ CHEST DC 8453 is at 96% of its DD rating • Operability: Limited jumpering options available • Other: ○ There have been three Method of Service requests since January 2021 totaling 2.3MVA load increase at NBALT substation. ○ There have been 6 Method of Service requests since January 2021 bring 2.24MVA of load to CHEST substation.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 109

(a)

(b)

Program:	System Loading: New Baltimore/Chesterfield
Scope:	• Procure (1) property • Install (1) new 120-13.2 kV substation • Upgrade (1) existing substation from 4.8 kV to 13.2 kV • Install (~2) miles of underground distribution cable • Install (~1) miles of conduit • Preconvert/Convert (~12) miles of overhead • Install (2) new circuits • Reconfigure existing circuits

(a)

(b)

Program:	System Loading: New Baltimore/Chesterfield				
Benefits:	• Increase capacity in area (~32% increase in capacity for NBALT and additional ~25 MVA capacity available with new substation) • Eliminate the over firm situation at New Baltimore substation • Eliminate the over firm situation at Chesterfield substation • Eliminate stranded load at NBALT substation • Provide jumpering options for area • Provide capacity for load growth in the area • Bring distribution circuits below their day to day ratings at NBALT and CHEST substations				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: New Baltimore/Chesterfield			
Approximate Construction Schedule:	2024: Engineering & Property Identification, Potential Design 2025 - 2027: OH Design - NBALT OH Circuit Pre-conversion 2028: NBALT 4.8 kV Substation Decommissioning 2028: CHEST Substation Construction 2029: NBALT TRF5 Installation 2029: NBALT 13.2 kV Substation Decommissioning 2030: NBALT CLASS-R Construction 2030: NBALT and CHEST Final Circuit Reconfiguration			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 46,591,044			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$250,000	\$744,516
	Material	\$ 0	\$ 0	\$100,000
	Other	\$ 0	\$ 0	\$1,500,000
	Total	\$ 0	\$250,000	\$2,344,516

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Otsego/Capac/Shaw
Purpose and Necessity:	This project will construct a new 13.2 kV substation to relieve load from CAPAC and OTSGO. Drivers for the project include the following: Reliability: – CAPAC average SAIFI from 2019 to 2022 is 2.02 – CAPAC average SAIDI from 2019 to 2022 is 631.97 – CAPAC average CAIDI from 2019 to 2022 is 370.86 – OTSGO average SAIFI from 2019 to 2022 is 1.46 – OTSGO average SAIDI from 2019 to 2022 is 703.97 – OTSGO average CAIDI from 2019 to 2022 is 402.17 Capacity: – OTSGO Substation is 4.4 MVA over, or 129% of the firm rating of 15.1 MVA – CAPAC Substation is 0.2 MVA over, or 101% of the firm rating of 13.5 MVA Operability: – OTSGO and CAPAC both have LTBT blocking installed which would block the automatic throwover at the substation if it would cause an overload. This could cause stranded load. – OTSGO and CAPAC have limiting jumpering options. – Both OTSGO and CAPAC have 13.2 kV circuits with large ISO down 4.8 kV areas. Other: – Execution is key to providing capacity on OTSGO substation to initiate a different project to move IMLAY load to OTSGO and allow for decommissioning of IMLAY
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 96

(a)

(b)

Program:	System Loading: Otsego/Capac/Shaw
Scope:	• Install (1) new 120-13.2 kV Class substation. Property Purchase will be required • Convert (110) miles of overhead conductor • Transfer load from OTSGO and CAPAC to new substation • Shaw substation will be at about 99.5% of firm after the System Loading: Brown City project. The Shaw scope is being removed from the Otsego/Capac/Shaw project.

(a)

(b)

Program:	System Loading: Otsego/Capac/Shaw				
Benefits:	- With the new Class 'R' substation, we will be able to relieve load from CAPAC, and OTSGO. - OTSGO 13.2 kV substation is projected to be at 163% of firm, after this project, OTSGO and CAPAC will be at 85% of firm. - The Otsego/Capac/Shaw project is a prerequisite to decommission IMLAY 4.8 kV.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	

(a)

(b)

Program:	System Loading: Otsego/Capac/Shaw			
Approximate Construction Schedule:	2023: Property Purchase 2023 - 2025: Engineering & Design 2026 - 2027: Substation Construction 2027: Substation in Service 2025 - 2026: OH Pre-conversion 2027: OH Conversion			
Budget Basis:	Project Management Estimate from 2023			
Total Cost: \1	The estimated project cost for this investment is \$ 191,850,771			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 87,746	\$1,429,210
	Material	\$ 0	\$ 0	\$188,157
	Other	\$151,334	\$ 0	\$ 0
	Total	\$151,334	\$ 87,746	\$1,617,367

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Port Sanilac
Purpose and Necessity:	Drivers for this project include the following: • Safety: Aging infrastructure has a risk of failure. 4.8 kV causes a higher safety risk in an event of a wire-down. • Reliability: Forester has aged Line Section Breaker (LSB.) in need of replacement. Installed in 1988 and the only 40 kV LSB on the DTE system, there are no replacements available. 3-333kVA pole mount transformers at Forester are at-risk equipment at Forester substation. The circuits at Port Sanilac are limited by substation regulators that are considered at-risk with no spare parts available. • Capacity: ○ Forester substation is a Class T substation with a single circuit. The substation is 125% of its firm rating and the circuit is at 125% of its day-to-day rating. ○ Port Sanilac is a Class T, 4.8 kV substation with two circuits. The substation is 88% of its firm rating with both circuits approaching 90% of their day-to-day rating. Port Sanilac substation's 5-year average (2018-2022) has been 105% of its firm rating. • Operability: Port Sanilac substation is surrounded by Thumb Electric. The loading on Port Sanilac substation and surrounding substations has increased to a point which new load cannot be adequately served. There are limited/no jumpering options during peak since Port Sanilac is surrounded by Forester and Applegate substations both of which are approaching/exceeding their substation transformer limits.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 93

(a)

(b)

Program:	System Loading: Port Sanilac
Scope:	Project 1: Property for new substation • Purchase (1) substation property Project 2: PTSAN DC 302 OH Pre-conversion Work • Pre-convert (17) miles of overhead from 4.8 kV to 13.2 kV • Pre-convert (1.6) miles of underground from 4.8 kV to 13.2 kV • Convert (17) miles of overhead from 4.8 kV to 13.2 kV • Convert (1.6) miles of underground from 4.8 kV to 13.2 kV Project 3: PTSAN DC 301 OH Pre-conversion Work • Pre-convert (20) miles of overhead from 4.8 kV to 13.2 kV • Pre-convert (1.5) miles of underground from 4.8 kV to 13.2 kV • Install (4) isolation down transformer • Convert (20) miles of overhead from 4.8 kV to 13.2 kV • Convert (1.5) miles of underground from 4.8 kV to 13.2 kV Project 4: FOSTR DC 301 OH Pre-conversion Work • Pre-convert and convert (15) miles of overhead from 4.8 kV to 13.2 kV • Pre-convert and convert (0.8) miles of underground from 4.8 kV to 13.2 kV • Install (3) isolation down transformer • Convert and convert (15) miles of overhead from 4.8 kV to 13.2 kV • Convert and convert (0.8) miles of underground from 4.8 kV to 13.2 kV Project 5: Substation Work – New 40 kV-13.2 kV Class T • Install (1) new 40-13.2 kV substation • Install (1) Line section breaker Project 6: Decommission PTSAN Sub

(a)

(b)

Program:	System Loading: Port Sanilac
	- Decommission (1) 40 kV-4.8 kV substation Project 7: Substation Work – FOSTR - Install (1) 40 kV-13.2 kV substation Project 8: Transfer load to new FOSTR sub - Load transfer (1) circuit

(a)

(b)

Program:	System Loading: Port Sanilac				
Benefits:	• Improve reliability • Improve voltage issues • Increase OH jumpering • Reduced 4.8 kV construction and build to 13.2 kV to align with DO conversion vision • Provide additional capacity for the future load growth • Transfer all load from FOSTR and decommission substation which is at 100% of firm • Transfer all load from PTSAN and decommission substation which is at 103% of firm				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Port Sanilac			
Approximate Construction Schedule:	2023-2027: Engineering & Design 2024-2027: Design and Pre-Conversion 2025 - 2026: Substation Construction 2025 - 2026: Conduit 2026-2027: Cable 2028: Substation In Service 2028: OH Conversion 2028: Decommission FOSTR Sub & PTSAN (equipment) 2028 - 2031: Rebuild FOSTR Sub (include conduit and cable)			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 85,321,374			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 34,811	\$1,920,366	\$6,211,291
	Material	\$ 0	\$469,004	\$3,034,339
	Other	\$402,880	\$ 0	\$ 0
	Total	\$437,691	\$2,389,370	\$9,245,630

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Richmond/Armada
Purpose and Necessity:	This project will construct a new 13.2 kV substation and decommission two aging 4.8 kV substations. Drivers for the project include the following: • Safety: 4.8 kV causes a higher safety risk in an event of a wire-down. Aging substation infrastructure has a risk of failure. • Reliability: The 4.8 kV switchgear at Richmond substation was installed in 1956 and is the only oil filled truck type outdoor switchgear remaining on the DTE system. The breakers along with the current transformers (CT) have no spare parts available. • Capacity: ○ Richmond's 4.8 kV substation is 96% of its firm rating. RICHM DC 2496 is at 83% of its day-to-day rating. ○ Armada substation is adjacent to Richmond substation. The 4.8 kV portion of the Armada substation is 112% of its firm rating and ARMAD DC0302 is 112% of its day-to-day rating. ○ The 13.2 kV side of Armada substation is 80% of its firm rating and its transformer is 80% of its day-to-day rating. The substation's 5-year average (2018-2022) has been 98% of its firm rating. • Operability: Armada has limited jumpering options so when the substation needs maintenance, a portable substation is required to pick up the load.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 94

(a)

(b)

Program:	System Loading: Richmond/Armada
Scope:	Project 1: • Install (1) new 40-13.2 kV substation • Install (2) 15/20/25MVA transformers • Install (1) 9 position switchgear • Install (10) cable poles • Install (411) ft. of conduit • Install (1500) ft. of system cable • Load transfer (1) circuit Project 2: • Pre-convert and convert (15) miles of overhead from 4.8 kV to 13.2 kV • Install (2000) ft. of system cable • Install (5) ISOs • Remove (4) ISOs • Install (4) reclosers • Remove (2) regulators • Remove (2) Caps Project 3: • Decommission (2) 40 kV-4.8 kV substations • Install (1) 40 kV Cap Project 4: • Pre-convert and convert (12) miles of overhead from 4.8 kV to 13.2 kV • Pre-convert and convert (4.2) miles of underground from 4.8 kV to 13.2 kV • Install (1000) ft. of system cable

(a)

(b)

Program:	System Loading: Richmond/Armada				
Benefits:	• Eliminates insertion and removal of breakers using a cart set on an outdoor elevated platform. Breakers rack out directly outdoors. • Replaces old oil filled breakers with modern vacuum style breakers. • Reduces time and cost to perform a breaker inspection • Substation will be more reliable with the ability to pickup load from a dedicated throwover circuit • Decommission 4.8 kV substations and bring ARMAD substation and RICHM substation under firm • All circuits will be below 90% of DD Rating • Provide reliable jumpering option to ARMAD 13.2 kV instead of using the portable substation for any work require shutdown of the substation • Current RICHM 4.8 kV firm is 96% and 13.2 kV is 63%. After project completion, new RICHM firm will be at 49% • Provides more capacity for growth and relieve adjacent substations • Cost reduction for pre conversion scope due to incorporating TIE810 subtransmission project • Provide more capacity for growth and relieve adjacent substations				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x	x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	System Loading: Richmond/Armada			
Approximate Construction Schedule:	Substation Construction: 2022-2024 Substation In Service: 2024 DC9328 Design and OH-Preconversion: 2022 - 2024 DC9679 Design and OH-Preconversion: 2022 - 2024 DC8359 Design and OH-Preconversion: 2024 - 2028 DC9887 Design and OH-Preconversion: 2023 - 2028 DC9241 Design and OH-Preconversion: 2023 - 2028 Install 40 kV Cap at RICHM: 2028-2029 Decommission RICHM 4.8 kV Substation: 2029 Decommission ARMAD 4.8 kV Substation: 2029			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 54,095,999			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$7,225,920	\$7,803,645	\$4,463,836
	Material	\$1,190,957	\$1,089,355	\$1,687,764
	Other	\$ 0	\$ 0	\$ 0
	Total	\$8,416,877	\$8,893,000	\$6,151,600

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Spokane/Seneca
Purpose and Necessity:	This project addresses loading and capacity concerns at Spokane and Seneca substations by expanding Spokane substation. Drivers for the project include the following: • Safety: - Substation flooding due to the lack of a drainage system at Spokane substation has damaged the conduit system by causing it to cave in. - This has impeded the use of the 9-position switchgear and the associated third transformer at the site. • Capacity: - Spokane substation is a 120-13.2 kV substation with seven load carrying circuits. The substation is at 120% of its firm rating. - Seneca is a 120-13.2 kV substation. It is a walled substation and does not have the footprint to accommodate an expansion. The substation is 125% of its firm ratings. - Tienken is a 120-13.2 kV substation which is at 102% of its firm rating. One circuit is over its day-to-day rating. • Operability: - Limited jumpering options outside of Spokane substation due to overloads at adjacent Seneca and Tienken substations • Other: - DTE's Equipment Performance and Protective Maintenance group recommends the replacement of the current 11-position switchgear, as it is at risk of failure.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 105

(a)

(b)

Program:	System Loading: Spokane/Seneca
Scope:	• Installing (1) 12-position switchgear • Replacing (1) 12-position switchgear • Installing (5) miles of system conduit • Installing (15) miles of system cable • Installing (12) Pole Top Switches • Installing (21) reclosers to establish loop schemes • Rebuilding (0.2) miles of overhead conductor

(a)

(b)

Program:	System Loading: Spokane/Seneca				
Benefits:	- Spokane substation capacity will increase by (50%) - Replace at-risk equipment at Spokane Substation - Establish a drainage system at Spokane Substation to address substation flooding - Provide load relief to both Spokane and Seneca Substations - Improved jumpering - Improve operability by establishing loop schemes				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	System Loading: Spokane/Seneca			
Approximate Construction Schedule:	2024: Engineering 2025: Engineering/Design/Construction 2026 - 2028: Construction			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 29,085,914			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$62,396	\$0	\$3,011,017
	Material	\$0	\$0	\$1,973,228
	Other	\$0	\$0	\$0
	Total	\$ 62,396	\$ 0	\$4,984,245

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Sterling
Purpose and Necessity:	This project will address capacity and loading concerns at Sterling substation by expanding the substation. Drivers for the project include the following: • Capacity: - Sterling Substation serves nine load carrying circuits. - In Summer 2022, one (1) Distribution Circuit DC 8624 was at 98% of its normal day-to-day limit. - There is evidence of re-development and steady growth still coming into the Substation area, particularly on DC 8442 that has exceeded its nominal day-to-day limit. - Load cannot be transferred to adjacent circuits without causing similar loading issues. - There are no positions available at Sterling Substation to create new circuits to provide relief and additional capacity. • Operability: Load cannot be transferred or jumpered to adjacent circuits without causing loading issues on those circuits. • Other: The current switchgear at Sterling substation is not the standard DTE setup. It is a straight bus switchgear which is exposed to a single point of failure.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 106

(a)

(b)

Program:	System Loading: Sterling
Scope:	• Installing (1) new 120-13.2 kV substation • Decommissioning (1) 40-13.2 kV substation • Installing (3) miles of system conduit • Installing (5) miles of system cable • Installing (10) reclosers • Installing (2) pole top switches

(a)

(b)

Program:	System Loading: Sterling				
Benefits:	- Increase the capacity at Sterling substation by (54%) - Create new jumpering opportunities between Sterling Circuits - Establish automatic loop schemes to improve reliability - Replacing at-risk switchgear				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x	x	x

(a)

(b)

Program:	System Loading: Sterling			
Approximate Construction Schedule:	2023: Engineering 2024: Design 2025: Conduit 2026: Cable/Overhead 2027-2028: Overhead			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 10,882,978			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$336,105	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$336,105	\$4,727,280

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Tahoe
Purpose and Necessity:	Tahoe Substation was built in 1998 and is a two transformer 13.2 kV substation. This project will expand Tahoe substation with a third transformer. Drivers for the project include the following: • Safety: Added capacity will facilitate 4.8 kV conversion (wire down mitigation) • Capacity: Tahoe substation is at 117% of its firm rating of 38.3MVA with a peak load of 44.8MVA. Transformer 2 is expected to be at 88% of its day to day rating. • Operability: Current loading conditions inhibit the creation of jumpering points and installation of loop schemes in the area.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 108

(a)

(b)

Program:	System Loading: Tahoe
Scope:	This is preliminary scope and will be refined during detailed engineering: • Upgrade substation with new 15/20/25 MVA transformer • Build (0.2) miles of system conduit • Install (2.0) miles of system cable • Install (3) miles of new OH conductor for 40 kV Trunk lines • Reconductor (1.2) miles of OH conductor for 13.2 kV distribution lines • Explore the implementation of new URDs to remove OH wire • Install sectionalizing with new 3-phase reclosers, fuses and pole top switches

(a)

(b)

Program:	System Loading: Tahoe				
Benefits:	- Tahoe substation firm rating is expected to double (50% increase). 24MVA of immediate capacity will be available through the three available circuit positions at TAHOE. - Alleviate the Day to Day (D-D) overloads at circuit & substation level with the installation of a third transformer at Tahoe - Reduce new customer connection timeframe and cost - Establish new jumpering points				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:			x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	System Loading: Tahoe			
Approximate Construction Schedule:	Year by year schedule until project is complete. SCHEDULE: 2025: Conceptual Engineering 2026/2027: Substation Design/Overhead Design/Cable & conduit. Design & major equipment purchase. 2027/2028: Substation Construction & circuit construction/load transfers, etc.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 7,539,720			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$100,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$100,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	System Loading: Wixom
Purpose and Necessity:	This project will expand Wixom substation to address loading and capacity concerns. Drivers for this project include the following: • Safety: Existing PDC and TRF1 are in close proximity, which is a fire hazard and is a worker safety hazard. In addition to the loading concerns at the substation, the existing switchgear at the substation is reaching its end of life and the breakers are at an elevated risk due to interruption medium. • Reliability: SAIDI fluctuates year after year for WIXOM circuits and a few circuits exceed DTE system average. Most outages occur during storm. • Capacity: WIXOM is over firm (106%). 6 of 7 WIXOM circuits are over 8MVA. The 7th circuit will be at 8MVA with customer load addition. 4 of 7 circuits are above nominal cable day-to-day ratings. • Operability: When a substation transformer fails, then at least (2) diesel generators are needed to support load at summer peak. There are only (2) jumpering points outside of Wixom substation at summer peak. • Other: Receiving multiple method of services (customer load requests). WIXOM cannot support industrial customers due to existing circuit loadings.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 16, Line 103

(a)

(b)

Program:	System Loading: Wixom
Scope:	• Expand (1) existing 120-13.2 kV substation • Installing (5.5) miles of system conduit • Installing (17.5) miles of system cable • Rebuilding or replacing (11.2) miles of overhead conductor • Installing (1.8) miles of new conductor

(a)

(b)

Program:	System Loading: Wixom				
Benefits:	• Current firm is 61MVA, new firm will be 122MVA. Capacity increase of 100%. • Provide capacity to serve existing and new customer load. Provide load to the Wixom-Assembly Park and future city developments. • Reduce major substation outage risk • Create circuit jumpering points to improve operability • Create capacity for future industrial customers • Support decommission of 4.8 kV WALLK • Relocate PDC1 due to its proximity to transformer 1, which creates a fire hazard				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:		x	x		
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x	x	x	x

(a)

(b)

Program:	System Loading: Wixom			
Approximate Construction Schedule:	2023 - Engineering, ITC Site Approval & EI approval, 2024 - Engineering & Detailed Design 2025 - Engineering, Detailed Design, Substation construction and start Conduit Construction and overhead construction 2026 - Detailed Design, Substation construction , Conduit Construction & Overhead Construction 2027 - Detailed Design, Conduit Construction, Cable Construction & Overhead Construction 2028 - Cable Construction, Overhead Construction/Load Transfers 2029 - 2030 - Cable Construction, Overhead Construction/Load Transfers			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 65,504,612			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$66,356	\$2,032,875	\$3,500,00
	Material	\$2,591	\$0	\$3,500,00
	Other	\$2,791	\$0	\$0
	Total	\$ 71,737	\$2,032,875	\$7,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	TCHPP Switchyard Upgrades
Purpose and Necessity:	Trenton Channel Power Plant (TCHPP) is being decommissioned and the existing Trenton switchyard will change operational authority from Energy Supply to Distribution Operations. In order for Transfer of Operational Authority to occur, the switchyard must be upgraded and brought up to current DO standards.
Category:	Infrastructure Redesign and Modernization
Line Number:	Exhibit A-12, Schedule B5.4, Page 14, Line 26

(a)

(b)

Program:	TCHPP Switchyard Upgrades
Scope:	The Trenton Switchyard Upgrades will include two new house services. The house services will service load to the new control center. HS 101 (normal) and HS 102 (alternate) are to be fed off of the 24 kV secondaries of transformer 101 and 102. Install new control center to accommodate the following equipment: – HSTO – Station AC Panel – Station Battery – Station DC Panel – Move Relay Panels for Transformer 101 and Transformer 102 from ITC Control Center to new control center

(a)

(b)

Program:	TCHPP Switchyard Upgrades				
Benefits:	– Transfer of Operational Authority from ENS to DO. – Bring equipment up to current substation standards.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	TCHPP Switchyard Upgrades			
Approximate Construction Schedule:	- First Year Work Scope: - Design services for the two new house services and control center. - Fabrication and procurement of the new control center. - Bid and award construction contractor to perform the work. - Begin Construction Q4 of 2023 - Second Year Work Scope: - Construction of New control center, HSTO, station AC panel, station battery, station DC panel, move relaying from TRF 101 and 102 from ITC control center to new control center.			
Budget Basis:	Engineering Estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 5,662,037			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,564,645	\$2,862,855	\$ 19,821
	Material	\$768,987	\$445,730	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,333,631	\$3,308,585	\$ 19,821

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

Investment	Capital Exhibit Reference
ADMS Enhancements.....4	Exhibit A-12, Schedule B5.4, Page 18, Line 32
ADMS: DMS/OMS 8	Exhibit A-12, Schedule B5.4, Page 17, Line 3
ADMS: Network Management System 12	Exhibit A-12, Schedule B5.4, Page 18, Line 41
AMI: Meter Communications Upgrades 17	Exhibit A-12, Schedule B5.4, Page 17, Line 17
Asset Management Upgrades.....21	Exhibit A-12, Schedule B5.4, Page 17, Line 21
Automation Configuration and Test Record Database.....25	Exhibit A-12, Schedule B5.4, Page 18, Line 38
Customer Power Status Visibility 29	Exhibit A-12, Schedule B5.4, Page 17, Line 18
CVR/VVO 34	Exhibit A-12, Schedule B5.4, Page 17, Line 8
DER Control 38	Exhibit A-12, Schedule B5.4, Page 18, Line 31
DERMS.....42	Exhibit A-12, Schedule B5.4, Page 18, Line 36
Distribution Automation 46	Exhibit A-12, Schedule B5.4, Page 17, Line 2
Distribution Planning 50	Exhibit A-12, Schedule B5.4, Page 18, Line 46
Distribution Sensing and Monitoring (inclg Line Sensors) 54	Exhibit A-12, Schedule B5.4, Page 17, Line 7
Enhance and expand cybersecurity 58	Exhibit A-12, Schedule B5.4, Page 18, Line 52
Enhance Maximo Capabilities and Processes 62	Exhibit A-12, Schedule B5.4, Page 18, Line 47
External Crew Efficiency 66	Exhibit A-12, Schedule B5.4, Page 17, Line 23
FLISR Implementation 70	Exhibit A-12, Schedule B5.4, Page 18, Line 35
Grid Automation Telecommunications 74	Exhibit A-12, Schedule B5.4, Page 17, Line 6
Grid Edge Insights & New Technology 78	Exhibit A-12, Schedule B5.4, Page 17, Line 30

Investment	Capital Exhibit Reference
Hosting Capacity Enablement 83	Exhibit A-12, Schedule B5.4, Page 18, Line 43
Interconnection Process Enablement 87	Exhibit A-12, Schedule B5.4, Page 17, Line 29
Load Forecasting & Analytics 92	Exhibit A-12, Schedule B5.4, Page 18, Line 42
Maintain Compliance 96	Exhibit A-12, Schedule B5.4, Page 18, Line 51
Meter Improvements 100	Exhibit A-12, Schedule B5.4, Page 18, Line 34
Microwave End of Life 104	Exhibit A-12, Schedule B5.4, Page 18, Line 39
Mobile Equipment Replacement 108	Exhibit A-12, Schedule B5.4, Page 18, Line 53
Mobile Technology 112	Exhibit A-12, Schedule B5.4, Page 18, Line 54
Mobile Tools Expansion 116	Exhibit A-12, Schedule B5.4, Page 18, Line 50
NWA: Adaptive Networked Microgrids 120	Exhibit A-12, Schedule B5.4, Page 17, Line 26
NWA: Battery Trailer 125	Exhibit A-12, Schedule B5.4, Page 17, Line 10
NWA: EV Charging Demonstration at ACM 129	Exhibit A-12, Schedule B5.4, Page 17, Line 28
NWA: Fisher Load Relief 134	Exhibit A-12, Schedule B5.4, Page 17, Line 12
NWA: Omega Load Relief 138	Exhibit A-12, Schedule B5.4, Page 17, Line 11
NWA: O'Shea Energy Storage 142	Exhibit A-12, Schedule B5.4, Page 17, Line 9
NWA: Port Austin Load Relief 146	Exhibit A-12, Schedule B5.4, Page 17, Line 13
NWA: Small Solar and Storage Testbed 150	Exhibit A-12, Schedule B5.4, Page 17, Line 14
NWA: Veridian 154	Exhibit A-12, Schedule B5.4, Page 17, Line 25
Operational Technology and Error Free Communication 158	Exhibit A-12, Schedule B5.4, Page 18, Line 33

Investment	Capital Exhibit Reference
Other Modernize Grid Management 164	Exhibit A-12, Schedule B5.4, Page 18, Line 40
Power Quality Analysis Program 169	Exhibit A-12, Schedule B5.4, Page 18, Line 44
Primary Service Orders Replatform 173	Exhibit A-12, Schedule B5.4, Page 18, Line 48
SCADA Remote Access and Configuration Platform.....177	Exhibit A-12, Schedule B5.4, Page 17, Line 19
Sensor, Network and Algorithm Development (Solar Deployment) 181	Exhibit A-12, Schedule B5.4, Page 17, Line 15
SOC: ASOC.....185	Exhibit A-12, Schedule B5.4, Page 17, Line 5
SOC: ESOC 189	Exhibit A-12, Schedule B5.4, Page 17, Line 4
Substation Cybersecurity 193	Exhibit A-12, Schedule B5.4, Page 18, Line 37
Substation Design Tool Upgrades.....197	Exhibit A-12, Schedule B5.4, Page 18, Line 45
Substation Reporting and Process Enhancements.....203	Exhibit A-12, Schedule B5.4, Page 17, Line 20
Systematic Tracking of Rotatable Assets 207	Exhibit A-12, Schedule B5.4, Page 17, Line 22
Technology Programs & NWA 211	Exhibit A-12, Schedule B5.4, Page 17, Line 16
Tree Trim Risk Prioritization Model.....215	Exhibit A-12, Schedule B5.4, Page 17, Line 24
Work Management & Scheduling Upgrades.....219	Exhibit A-12, Schedule B5.4, Page 18, Line 49

(a)

(b)

Program:	ADMS Enhancements
Purpose and Necessity:	Following the completion of the ADMS cutover/hypercare, the Company experienced a series of escalating weather events that created a need for a transformational response to storms and how our technology platforms enable this transformation. ADMS is a technology platform that will continue to evolve and improve as our customer needs and our outage/operational response changes over time. Continued investment will drive improved grid reliability, enhanced outage management, and cost savings via optimized asset utilization and ensuring our electric infrastructure has technology that continues to evolve to support it.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 32

(a)

(b)

Program:	ADMS Enhancements
Scope:	• Continued product enhancements to the core ADMS (improving outage analysis processing, new functionality, bulk event updating, wire-down dispatching, etc.) • Investing in ADMS advanced applications (network model, power flow, FLISR, etc.) • Enabling switch order management functionality (creating switching steps and executing orders within the ADMS). • Future platform/product version upgrade planning/execution with our ADMS vendor

(a)

(b)

Program:	ADMS Enhancements				
Benefits:	• Improve safety and restoration times by providing real-time situational awareness to all resources • Improve safety, reliability, and efficiency by eliminating paper maps and switching orders • Provide platform for Fault Location, Isolation and Restoration • Enable remote switching operations • Support integration of Distributed Energy Resources				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	ADMS Enhancements			
Approximate Construction Schedule:	2024: Continue improving AMI functionality within ADMS, user interface improvements within the system, continued work on network model/power flow to support multi-year initiatives (e.g., FLISR), next phase for SOM (create switching steps and execute orders related to switching and tagging). 2025: Continued work on ADMS/OMS improvements, FLISR implementation, new SOM processes (e.g., creating red tag records, installing red tags, moving them through workflows), planning for next version upgrade for platform/products.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 35,000,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$6,000,000	\$6,000,000
	Material	\$ 0	\$1,000,000	\$1,000,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$7,000,000	\$7,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	ADMS: DMS/OMS
Purpose and Necessity:	The previous DMS and OMS systems were outdated, non-integrated, and with partial functionality. The existing infrastructure supporting the software was no longer commercially available, increasing the risk of recoverability from system failures, and putting the safe operation of the electric system at risk. The previous DMS and OMS systems were developed by separate companies and not built on a common data platform. The lack of interoperability between the two systems made real-time operation and analysis inefficient and difficult. Collectively this meant the Company could not upgrade without replacing the hardware (~15 years old) and performing a significant upgrade of the application software.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 3

(a)

(b)

Program:	ADMS: DMS/OMS
Scope:	• Purchase software and hardware for DMS/OMS systems • Install DMS/OMS portion of the ADMS to integrate various operational technologies and analytical tools. • Integrate new systems with other key systems, such as mapping and customer information systems like AMI to provide. • potential switching and dispatching solutions to these personnel to reduce the cost and time of outages. • Install functions to perform all electrical system analysis from a single view of the system. • Install functions to perform digital switch orders to enhance employee safety in the field.

(a)

(b)

Program:	ADMS: DMS/OMS				
Benefits:	• Enhance safety and restoration times by providing real-time situational awareness to all resources • Enhance safety, reliability, and efficiency by eliminating paper maps and switching orders • Provide platform for Fault Location, Isolation and Restoration • Enable remote switching operations • • Support integration of Distributed Energy Resources				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:	x	x		x	x

(a)

(b)

Program:	ADMS: DMS/OMS			
Approximate Construction Schedule:	2022: Continued development and testing of Outage Management System (OMS), EMS upgrade, Field Service Mobile, and eMAP applications. Initial roll out of Distribution Management System (DMS) 2023: Roll out and in-service of OMS, EMS Upgrade, Field Service Mobile, and eMAP			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 93,444,054			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$7,837,942	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$1,432,292	\$ 0	\$ 0
	Total	\$9,270,234	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	ADMS: Network Management System
Purpose and Necessity:	The foundation for the evolving Distribution Planning processes is a high-quality network model including grid topology and electrical characteristics. Network model investments include technology to better align field conditions and maps to the digital representation of the grid, integrations between asset systems, new data models to support planning and operations topology and characteristics, and advanced analytics to leverage sensor data to continuously improve the network model.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 41

(a)

(b)

Program:	ADMS: Network Management System
Scope:	• Common platform operating maps - Configuration and software scripts developed to support cartographic representations of subtransmission, AC Network, and URD maps. Transfer, reconciliation, and field validation of the new configuration within the ESRI platform. • Asset data integrations - software integration among enterprise asset systems (Maximo, ESRI, SAP) for electric asset data. • Network model enhancements - additional detailed data model configuration and initial attribution to support electronic switching and tagging, as well as future distribution planning processes such as hosting capacity and scenario analysis. • Grid model analytics - leverage the enterprise data platform to explore and develop machine learning algorithms to address data quality gaps based on existing and derived information. Once the algorithms are tested and proven, DTEE will integrate the machine learning workflow with source systems to raise overall data effectiveness. • Network Model orchestrator (beyond 2025) - select and implement software solution to manage network model versions for planned work, including scenario configurations.

(a)

(b)

Program:	ADMS: Network Management System				
Benefits:	• Provide foundation needed to deploy advanced grid simulations and analytics called for by the evolving distribution network. • Improve situational awareness by generating operating maps used in the field from the same source that is powering planning and operations electronic tools. • Perform data input and maintenance efficiently through asset data integrations and algorithms to address data quality gaps.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	ADMS: Network Management System			
Approximate Construction Schedule:	2024: - Continue the work in supporting ADMS with network data models on a daily basis - Support requirements for ADMS advanced applications (e.g., DPF and FLISR) - Add 10 new data fields to network model - Grid model analytics: improve data quality for primary and sub-transmission overhead/underground lines by 10% - Asset data integrations: synchronize 4 asset types between GIS and Maximo - Implement AC network connectivity 2025: - Continue the work in supporting ADMS with network data models on a daily basis - Support requirements for ADMS advanced applications (e.g., DPF and FLISR) - Add 5 new data fields to network model and improve/develop new algorithms to enhance phasing and meter to transformer connectivity - Grid model analytics: improve data quality for smart fault indicators and DERs by 10%			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,943,166	\$ 1,555,817	\$ 2,722,679
	Material	\$ 55,106	\$ 44,121	\$ 77,212
	Other	\$ 78	\$ 62	\$ 109
	Total	\$1,998,350	\$1,600,000	\$2,800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	AMI: Meter Communications Upgrades
Purpose and Necessity:	Public Wireless Telecommunication providers are phasing out 3G cellular in Michigan by the end of 2021. After this date, 3G technology will no longer be supported, and existing 3G devices will not be operable with the cellular 4G platforms. The existing AMI metering deployment is dependent on 3G cellular public carrier service for approximately 1 million of the 2.6 million customer electric meters and all data for customer billing, outage analysis, electric grid analytics, etc. Without this technology transition from 3G cellular to 4G cellular, all AMI benefits related to 1.1 million residential and small commercial meters will cease and these meters will no longer be remotely accessible for billing, outage detection, voltage data or remote connect / disconnect capabilities, severely impacting customer service.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 17

(a)

(b)

Program:	AMI: Meter Communications Upgrades
Scope:	Update technology to operate on 4G public cellular networks: • Replace 2,700 3G cell relays with 4G devices • Optimize deployments to reduce seasonal vegetation impact • Sustain network performance & remediate coverage gaps

(a)

(b)

Program:	AMI: Meter Communications Upgrades				
Benefits:	• Mitigate the impact of cellular 3G phase out by public wireless carriers on the existing AMI network, and attendant customer focused services. • Increase reliability of AMI reporting, by providing faster data collection during outages, increase the frequency of normal day-to-day data receipt and reduce network disruptions caused by vegetation. • Enable use of the AMI infrastructure as a shared infrastructure for future expansion of circuit automation.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	AMI: Meter Communications Upgrades			
Approximate Construction Schedule:	Program completed in 2022			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 10,135,829			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Asset Management Upgrades
Purpose and Necessity:	Managing the electric grid is an asset-intensive operation, and, as such, relies heavily on the capabilities of its Asset Management systems. The overall goal of effectively managing assets is to minimize the total cost of ownership and operations while delivering the desired service levels. This includes maintaining access to accurate digital data about the asset, algorithms to process and analyze data, and a visual context of an asset's location and condition. Asset management includes managing the full lifecycle of an asset, engineering and financial management, as well as linking spatial information in the ESRI Mapping system to an asset.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 21

(a)

(b)

Program:	Asset Management Upgrades
Scope:	Storm Reporting and Analysis Server: Acquire a standalone server with more computing power for storm reporting and analytics such as: weather data collection and processing, storm forecasting model, wire-down application, circuit prioritization model, and trouble-behind-trouble report(s). ESRI Windows servers replacement: The existing DTE Outage Map ESRI servers were running Windows Server 2012 and an older version of ESRI platform. These servers need to be upgraded to the current standards, Windows Server 2022 and ESRI 10.8.1. This service is used by DO field resources to view the outage polygons in the Outage Status App (OSA), Field Service Edge(FSE), and System Outage Screen (SOS) report Maps pages. Brigade 360 Cameras: Order and install cameras so drivers have full visual awareness of hazards and fixed objects surrounding the vehicles to safely maneuver and prevent vehicle accidents. • Service operations vehicles (567 work trucks and 171 supervisor vehicles) • Substations vehicles (89 work trucks and 100 supervisor vehicles) • WWSC (70 work trucks and 25 supervisor trucks) Tree Trim – ESRI upgrade to Enterprise 10.8.1 and Windows Server 2019: Upgrade and migrate tree trims ESRI servers to ensure we’re on a stable and supported version of our applications and server components. ArcGIS Enterprise Tree trim Server and Portal 10.6.1 was retiring on January 1, 2024. Migration to version 10.8.1 for Server and Portal from the 10-year-old Windows 2012 R2 servers to 2019 is necessary. 2012 R2 was decommissioned as of October 10th, 2023.

(a)

(b)

Program:	Asset Management Upgrades				
Benefits:	- Purchasing of new servers to replace outdated servers for DTE Outage map and storm reporting and analysis applications are necessary investments to ensure the key apps function and are compliant with IT security protocols. Other benefits include faster storm analytics and escalation during storm. - Brigade 360 cameras investments were made with the goal of decreasing motor vehicle incidents, measured by the Collisions per Million Miles (CPMM) metric. Since inception, motor vehicle accidents have decreased from 140 (2022) to 119 (2023), marking a notable 17% improvement. It's crucial to note that factors like inclement weather and road conditions affect this metric, and this investment is part of a broader effort to enhance vehicle safety. Lowering vehicle incidents not only enhances public safety but also reduces expenses associated with repairing or replacing damages, contributing to overall affordability of our products. - Tree trim ESRI upgrade was necessary to stay within security compliance with Microsoft, ESRI, and DTE's security policies.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Asset Management Upgrades			
Approximate Construction Schedule:	2022/2023 Projects: • Rubber Glove Tracking • Storm Reporting and Analysis Server • Replace obsolete ESRI Windows servers for internal Outage Map Polygons for OSA, SOS, and FSE/Lemur Pro • Brigade 360 Cameras • Tree Trim – ESRI upgrade to Enterprise 10.8.1 & Windows Server 2019			
Budget Basis:	IT Estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 5,532,203			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$990,459	\$ 0	\$ 0
	Material	\$262,580	\$ 0	\$ 0
	Other	\$868,319	\$ 0	\$ 0
	Total	\$2,121,358	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Automation Configuration and Test Record Database
Purpose and Necessity:	Relay and SCADA Configuration Data was migrated from an obsolete FOCUS database when WINDOWS XP was retired. The current database tool is functioning but is at risk of not being improved or supported due to its custom design. When migrating from FOCUS to the new tool, SCADA data was not added to the database and is currently stored on network drives. Due to process issues and lack of software support, the status of certain protection settings is not accurate and requires manual data entry and conversion. This project would procure a tool that would perform those functions and augment the asset and work management processes already developed. Relay and SCADA Configuration data is important to accurately record. NERC CIP dictates how protection settings need to be calculated for assets and these settings would be stored in the database. The integration with this software will streamline work in System Protection and Automation. Streamlined tools also have built in workflow tools that allow data to be automatically updated. This will help to ensure the accuracy of the status of the data in the database and the coordination with the work management system, Maximo.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 38

(a)

(b)

Program:	Automation Configuration and Test Record Database
Scope:	• Data Preparation and Conversion ○ Review test records and update relay settings status' in current database ○ Identify missing settings and add to the existing database ○ Flag NERC relay configurations • Evaluate Software Options ○ Reach out to vendors for quotes, specifications, and capabilities, conduct RFP ○ Compare and select software • Purchase software, order hardware, install and configure • Develop standards and job unit materials for engineers and technicians • User implementation • Go live

(a)

(b)

Program:	Automation Configuration and Test Record Database				
Benefits:	• Automate relay testing and test record process • Improved accuracy of data which will ensure NERC compliance • Rapid discovery of equipment configuration via search tools • Audit and version history for data and configuration settings • Automatic and preconfigured test routines • Streamline coordination studies with data link to short circuit modeling tools				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Automation Configuration and Test Record Database			
Approximate Construction Schedule:	Automation Configuration and Test Record Database (Relay Database) 2022-2029 2024/2025: Implementation of phase 1 - Database setup and migration. 2026 and Beyond: Interface development to automate data flow between the relay database and other applications.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 8,004,385			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 200,000	\$ 3,200,000
	Material	\$ 0	\$ 1,200,000	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$1,400,000	\$3,200,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Customer Power Status Visibility
Purpose and Necessity:	In 2022, DTE Customers experienced a series of serious storm events that resulted in extended outage restoration times. These events, and the experiences that resulted from them, highlighted a significant opportunity in how the Company intended to interact with our customers during these most impactful service interruptions. The Company listened to our customers and what they told us was both simple and foundational to a series of investments. They expect that we know before they do that power has been interrupted, that we communicate with them appropriately, and that when we do communicate our communications are timely and accurate. This has led us to the following drivers for this program: • Maximize the Number of Customers that are included in our outage communications • Maximize the Accuracy of our first and all subsequent estimates provided to customers • Maximize the timeliness of delivering our first estimate to the customer • Maximize our ability to predict customer outages where no direct information is available • Minimize the number of Ok on Arrivals (crews sent to locations without active outages) This program will make a positive and measurable impact to all of these outcomes and by doing so improve Customer confidence and satisfaction with DTEE
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 18

(a)

(b)

Program:	Customer Power Status Visibility
Scope:	The Customer Power Status Visualization program will achieve its objectives through a combination of the following scope items: • Replacement of 3000 end of life Field Area Routers, that are no longer performing their intended function in all weather conditions, with up to date and fully functional devices. This replacement will result in more meter alarms and voltage information reaching the AMI system for consumption by our Outage Management System, Customer system, our digital channels and our error free communications infrastructure. All of these FAR's will now have a direct connection to our AMI system reducing the number of communications hops currently in the system to zero. • Installation of 500 additional FAR's to be placed in densely populated areas reducing the number of meters each FAR manages to minimize our data loss from oversaturation. • Installation of 22,000 cellular meters placed strategically near each system reclosure in order to understand the actual energization status of that device even without having a Scada device installed at that location allowing system operations to more accurately model and isolate outages. • Deployment of in premise or on meter communications devices in areas where mesh design or other factors make meter communications intermittent as a secondary way of understanding the power status at select premises (prioritization to schools or at risk customers first). • Deploy a suite of monitoring and visualization tools for real time information on all components of the AMI network in real time for operational response. • Design, staff and deploy a permanent AMI Network Operations Center to monitor the AMI communications network with rigor and operational awareness at the same level that we monitor the electric grid that it serves. This will include dedicated monitoring, dispatching and field resources to keep the AMI network operational during significant events.

(a)

(b)

Program:	Customer Power Status Visibility
Benefits:	The CPSV Project will provide the following benefits by the end of the Phase 1 period ending in December 2024: • Maximize the number of customers that are included in our outage communications. In 2023, the Company included ~60 % of our customers in proactive customer communications. When this project completes its Phase 1 objectives, this percentage will be improved by ~20% bringing our overall percentage to ~72%. • Maximize the accuracy of our first and all subsequent estimates provided to customers. DTEE measures estimate accuracy for all customers that have meters that successfully provided a Power Out Notification to the AMI system. With the planned network improvements that population will be increased by 10-15%. • Maximize the timeliness of delivering our first estimate to the customer. With more alarms and voltage information making it to the AMI system the Company will be able to isolate and assess damage locations and severity improving our time to deliver the first estimate by 10% at the end of Phase 1 more quickly • Maximize our ability to predict customer outages where no direct information is available. All utilities have some number of customers that experience an outage and neither the AMI information or a customer call is available. These customers are identified by predicting their status based on information derived from information from their area and other confirmed outages. The more information available reduces the number of outages that must be predicted and increases the accuracy of the OMS outage prediction engine. By the end of 2024 this project will have made these predictions 10 – 15% more accurate. • Minimize the number of Ok on Arrivals (crews sent to locations without active outages). Due to the nature of a large scale event like a storm there will always be restoration jobs where a customers power is restored and the OMS still has an active job or jobs associated with this Customer. Sending a crew to a job that is already restored wastes valuable restoration capacity and prolongs restoration of real ongoing work efforts as crews report to false outage situations. The Company can locate instances of this condition if it can reliably get the meter status at these location and use that to determine if a crew is really needed. At the end of 2023 our OK on Arrival percentage for outage jobs during Storms was 26%. This project will reduce that by 25% bringing our overall performance for outage jobs during Storms to ~18% before other additional improvements to processes at factored in.

(a)

(b)

Program:	Customer Power Status Visibility				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					
Approximate Construction Schedule:	Q1 2024 through Q4 2026.				
Budget Basis:	- Improve Customer Experience through more timely, more accurate communication of the power status at a customer's premise. - Reduce OK on Arrivals. - Improve AMI data reception rate.				
Total Cost: \1	The estimated project cost for this investment is \$ 40,000,000				

(a)

(b)

Program:	Customer Power Status Visibility			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$5,309,038	\$4,005,481
	Material	\$ 0	\$10,633,076	\$8,023,462
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$15,942,114	\$12,028,943

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	CVR/VVO
Purpose and Necessity:	Volt Var Optimization (VVO) manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives. The objectives can include reducing losses, managing voltage volatility due to intermittent renewable generation, optimizing operating parameters, and/or optimizing power factors. Conservation Voltage Reduction (CVR), as one of the VVO options, is designed to maintain customer voltage levels in the lower portion of the allowable voltage ranges. This helps reduce system losses during peak demand or energy consumption.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 8

(a)

(b)

Program:	CVR/VVO
Scope:	Scope for 2024 to 2030 that leverages ADMS to achieve advanced CVR/VVO: • Install remote controls for existing overhead capacitor banks or install new smart capacitor banks at targeted locations. • Install remote controls for line regulators. • Install voltage sensors at strategic locations to monitor primary voltage levels. • Upgrade substation transformer load tap changers (LTC) with remote control capability to control bus voltage. • Implement the Volt-Var Control (VVC) module from the ADMS to allow real-time voltage control and optimization.

(a)

(b)

Program:	CVR/VVO				
Benefits:	CVR/VVO provides both a benefit to the distribution system as well as a generation alternative through reduced demand and energy consumption. Initial pilots conducted in 2020 through 2022 on six circuits using local control achieved peak reductions of 0.9% to 1.4% and energy savings of 0.7% to 1.0% and would be expected to raise to industry standard level 1.5% to 3% with the use of ADMS based CVR/VVO control. The CVR/VVO program is targeting a total peak demand reduction of up to 38 MW by 2030. In addition, CVR/VVO is, and will continue to be, a part of DTE Electric's integrated resource portfolio and are part of a utility system framework within the comprehensive context of an integrated resource planning process.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	CVR/VVO			
Approximate Construction Schedule:	2024: 22 circuits will be upgraded for \$2.5 million. Circuit upgrades include the replacement of 36 capacitors and controls, four regulator control replacements, and the installation of 20 voltage monitoring locations. This work will allow for ADMS monitoring and control of voltage through CVR/VVO modules. 2025: 22 circuits are expected to be upgraded for \$2.5 million. Circuit upgrades include the replacement of 40 capacitors and controls, two regulator control replacements, and the installation of 22 voltage monitoring locations. This work will allow for ADMS monitoring and control of voltage through CVR/VVO modules. In addition, the Company's scope of work includes a targeted capacitor control replacement program to address end of life capacitor controls that rely on time-based radio control. The existing radio controls have been obsoleted by the manufacture and spare components for the radio transmitter are at risk of not being available. The capacitor control replacement program portion of the 2025 scope includes \$5.6 million to replace 737 capacitor controls, bringing the total cost for 2025 to \$8.1 million.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,085,925	\$1,537,267	\$4,980,744
	Material	\$627,095	\$887,733	\$2,876,256
	Other	\$ 52,980	\$ 75,000	\$243,000
	Total	\$1,766,000	\$2,500,000	\$8,100,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	DER Control
Purpose and Necessity:	This investment is intended to provide the SCADA and backend changes required to support dispatchable Distributed Energy Resources (DER) integration at scale, and technical interfaces for support of FERC Orders 2222 and 841. Modernizing the company's existing telemetry and control capabilities for medium and large DER using industry-standard equipment will maximize visibility, lower the cost, and ultimately support the safe and efficient integration of these resources.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 31

(a)

(b)

Program:	DER Control
Scope:	Installation of one large DER interconnection gateway and multiple small interconnection gateways per year to replace end-of-life controls and monitoring at existing solar sites. • 30 sites are scheduled for replacement.

(a)

(b)

Program:	DER Control				
Benefits:	- Improved visibility into DER output translates into more efficient operations of the distribution circuits to which these units are connected. - More timely data acquisition supports the situational awareness of the control room, which translates into safer and more reliable operation. - Standardization of controls allows for validation of controls and hardware that may also be deployed at customer DER locations to enable advanced inverter functionality in the future.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	DER Control			
Approximate Construction Schedule:	Install one large interconnection gateway and multiple small gateways to add additional control per year at existing DTE solar sites, monitoring and cybersecurity functionality			
Budget Basis:	Engineering Estimate based on historical spend of similar installations			
Total Cost: \1	The estimated project cost for this investment is \$ 1,450,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$140,000	\$140,000
	Material	\$ 0	\$140,000	\$140,000
	Other	\$ 0	\$ 10,000	\$ 10,000
	Total	\$ 0	\$290,000	\$290,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	DERMS
Purpose and Necessity:	As more distributed energy resources are brought to the system from customers, there is a need to coordinate their operation and communicate to the highly diverse vendor and equipment landscape of customer owned DER and DR equipment. These dispatch signals need to be coordinated with system operations for reliability and system loading, system maintenance and coordinated with third party operators and market signals. DTEE needs to be able register and define what each resource is, how it is connected to the system, what constraints it has and what programs it participates in. There is also a need for this data interchange to occur securely and seamlessly with little overhead to the customer participating in various programs. The dispatch of systems needs to weight many factors beyond the physical and program constraints of the devices including impacts to loading, reliability and the forecasting of short and long term energy balances, loading and generation. This program aims to modernize the company's existing telemetry and control capabilities for medium and large Distributed Energy Resources using industry-standard equipment to lower the cost, maximize visibility and ultimately support the safe and efficient integration of these resources.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 36

(a)

(b)

Program:	DERMS
Scope:	Procurement of core ADMS interface modules and configuration of interfaces. Interfacing of system to DR and interruptible programs, linkage of system to support registration and deregistration of customers and DER assets into programs with configuration data of the DERs accurately represented in the system model. Integration of all DER and DR programs and resources into the system and compliance with FERC 2222 requirements as defined by MISO. Integration of DERA and ICCP connectivity for coordination and validation of operations.

(a)

(b)

Program:	DERMS				
Benefits:	- Improved visibility into DER output translates into more efficient operations of the distribution circuits to which these units are connected. More timely data acquisition supports the situational awareness of the control room, which translates into safer and more reliable operation. - Better visibility into distributed energy resources and their behavior - Coordination of dispatch signals to ensure reliable and safe operation without creating power flow or voltage violations.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	DERMS			
Approximate Construction Schedule:	2025: Licensing for core ADMS interface modules and beginning of configuration 2026: full licensing payment and completion of ADMS interface modules 2027: System configuration and integration of DR and interruptible programs 2028: Integration of remaining DER programs and FERC 2222 requirements			
Budget Basis:	IT Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$500,000
	Material	\$ 0	\$ 0	\$800,000
	Other	\$ 0	\$ 0	\$200,000
	Total	\$ 0	\$ 0	\$1,500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Distribution Automation
Purpose and Necessity:	Distribution Automation will automate ground detection and isolation, reducing the safety risk of energized down wire on the ungrounded 4.8 kV system and improving public safety and shifting resources during storm from public protection to restoration. Distribution Automation also includes improved Fault Location, Isolation, and Service Restoration (FLISR) capabilities which improve customer restoration; improved distribution system resilience to extreme weather which can limit the number of customer outages; more effective equipment monitoring and preventative maintenance to prevent equipment failures; more efficient use of repair crews; reduced repair times; and improved grid integration of DER.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 2

(a)

(b)

Program:	Distribution Automation
Scope:	The 2024 Distribution Automation Plan is composed of the investments included in the IRM in Case No. U-21297, which is 63 circuits and 189 reclosers, plus an additional 96 reclosers that are expected to improve 32 circuits on the 4.8 kV distribution system. In addition, engineering and design work will be completed in 2024 for 240 reclosers covering approximately 80 circuits to be constructed in 2025. In 2025, 578 reclosers across an estimated 242 circuits will be constructed based on the prioritization model developed in 2023 and 480 reclosers and 160 circuits are expected to undergo engineering and design in 2025 for 2026 construction.

(a)

(b)

Program:	Distribution Automation				
Benefits:	The planned Distribution Automation work for 2024 is expected to address ground detection and isolation for 63 circuits at 18 substations that is part of the IRM, and an additional 32 circuits at 11 substations. It is also expected to reduce SAIDI on impacted circuits by 45%, reducing system SAIDI by 9 minutes, based on the circuit level benefits modeling discussed earlier. The planned work for 2025 is expected to address ground detection and isolation for 281 circuits at 73 substations and is expected to reduce SAIDI on impacted circuits by 47% reducing system SAIDI by 45 minutes.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:	x				
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:		x	x		

(a)

(b)

Program:	Distribution Automation			
Approximate Construction Schedule:	In 2023, DTEE completed engineering and design standards for use of the Distribution Automation reclosers for 4.8kV and preliminary standards for 4.8kV ground detection and isolation, which will be finalized in early 2024 based on incorporating process improvements identified during initial deployments. DTEE has field installed 208 reclosers and commissioned 102 with fault isolation and remote operating capability, with the balance of 106 expected to be commissioned in early 2024. DTEE has also completed circuit level costs and benefits estimates, which will be used for circuit prioritization and program cost benefit estimation. The 2024 Distribution Automation Plan is composed of the investments included in the IRM in Case No. U-21297, which is 63 circuits and 189 reclosers, plus an additional 96 reclosers that are expected to improve 32 circuits on the 4.8 kV distribution system. In addition, engineering and design work will be completed in 2024 for 240 reclosers covering approximately 80 circuits to be constructed in 2025. In 2025, 578 reclosers across an estimated 242 circuits will be constructed based on the prioritization model developed in 2023 and 480 reclosers and 160 circuits are expected to undergo engineering and design in 2025 for 2026 construction.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$11,082,270	\$11,637,282	\$52,888,125
	Material	\$15,743,450	\$9,550,939	\$72,736,875
	Other	\$278,610	\$ 0	\$ 0
	Total	\$27,104,329	\$21,188,221	\$125,625,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Distribution Planning
Purpose and Necessity:	Distribution planning requires a number for tools to be developed and new use cases arise that may not be directly attributable to a specific project in a given year. Additionally, some smaller investments are not large enough to require an independent budget on their own. This project collects those smaller investments in the distribution planning space together and allows the initiation of emergent needs to move forward to provide needed value to planning and engineering. These smaller projects may develop into larger programs in the distribution planning space.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 46

(a)

(b)

Program:	Distribution Planning
Scope:	Investment in smaller or emergent distribution planning projects and technologies, including software upgrades to existing systems, interfaces, or purchases of new software.

(a)

(b)

Program:	Distribution Planning				
Benefits:	Rapid response to emerging planning needs and initiation of new projects that do not initially meet the threshold to have a fully independent budget.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Distribution Planning			
Approximate Construction Schedule:	2022: Load allocations and analytics tool to evaluate transformer overloads and EV loading. Required software licensing upgrades. 2023: Purchase of bluebeam CAD markup tool to streamline print modifications and facilitate faster design revisions. Necessary backend server upgrades that were identified during the CYME 9.2 upgrade and required software upgrades. AI model for cause code identification on outages. Software enhancements. A significant portion of 2023 investments were related to the Grid Management and were booked to this line item in error. 2024: Circuit Reliability optimization algorithms to assist planning on identifying appropriate solutions, additional investments in small distribution planning tools, scripting and interfaces. 2025 and on will include emergent investments			
Budget Basis:	Engineering Estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 13,051,408			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$7,513,261	\$1,122,000	\$1,150,000
	Material	\$457,195	\$450,000	\$450,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$8,447,019	\$1,572,000	\$1,600,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Distribution Sensing and Monitoring (inclg Line Sensors)
Purpose and Necessity:	Line sensors, also known as smart fault indicators, and low-cost substation monitoring equipment provides key situational awareness data to Distribution Operations, such as real-time fault status, magnitude, and near-real-time (5 minute) circuit loading information. These tools allow DTE to gain important visibility into parts of the grid where there is no existing SCADA solution and can defer costly equipment upgrades needed to implement a long-term SCADA solution. These devices also provide visual indication of faults at the installation location to help crews reduce restoration time. Furthermore, in an operational context, these devices enable shorter restoration times through a better understanding of the causes and locations of outages throughout our distribution system.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 7

(a)

(b)

Program:	Distribution Sensing and Monitoring (inclgd Line Sensors)
Scope:	• Install overhead line sensors on distribution circuits that do not have any source of fault locating data. • Replace defective line sensors and currently installed sensors that have obsolete telecommunication technology (cellular 3G). • Installation of pole sensors that measure physical damage to poles during and outage and alert a crew when a pole is broken or damaged or an adjacent line has come down. • Deploy underground smart fault indicators on underground circuits or portions of circuits with no other source of fault locating data. • Deploy underground smart fault indicators on A/C Network netbanks that don't have SCADA monitoring capability. • Deploy voltage-sensing smart fault indicators at key distribution locations, particularly those with high DER penetration. • Install low-cost substation monitoring equipment at 4.8kV substations that don't have SCADA, including both feeder and transformer positions. • Integrate PQ data from existing and new ION meters installed at low-cost monitoring substation transformer positions.

(a)

(b)

Program:	Distribution Sensing and Monitoring (inclg Line Sensors)				
Benefits:	• Help identify and locate faults and dispatch crews to the right location thereby reducing outage duration • Reduce patrol time and time to perform switching analysis and load jumpering • Provide more accurate load data for system planning and design • Enhance grid-wide situational awareness as a low-cost alternative to SCADA • Understand DER impacts to customer voltage and power quality • Improve customer reliability by avoiding approximately 20 M customer minute interruptions annually by 2026				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Distribution Sensing and Monitoring (inclgd Line Sensors)			
Approximate Construction Schedule:	2022: low-cost substation monitoring and replacement of obsolete sensors 2023: installation of 398 UG pad mount fault indicators, installation of 100 sensors, purchase of 300 Gridware pole sensors and 1000 Sentient Sensors 2024: Installation of 500 Sentient Sensors and 300 grid ware sensors, configuration of software and interfaces 2025: Installation of remaining Sentient line sensors and installation of 1300 UG fault indicators			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,232,802	\$450,000	\$600,000
	Material	\$5,104,462	\$ 0	\$300,000
	Other	\$214,439	\$ 50,000	\$100,000
	Total	\$6,551,703	\$500,000	\$1,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Enhance and expand cybersecurity
Purpose and Necessity:	Exposure of customer and operational data, critical infrastructure assets, and digital platforms to cyber threats increase as more grid technologies comes online. To help ensure the security of our grid from cyber threats DTE must comply with NERC-CIP regulation, cyber security standards, and requirements for controlling, monitoring, and supporting the electrical grid. This investment will maintain cybersecure technologies against the expanding threat landscape.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 52

(a)

(b)

Program:	Enhance and expand cybersecurity
Scope:	Included in this investment is software, hardware and/or database environment upgrades or replacements due to regulatory changes, obsolescence, and security vulnerabilities.

(a)

(b)

Program:	Enhance and expand cybersecurity				
Benefits:	- Protects customer and operational data, critical infrastructure assets and digital platforms from cyber threats. - Ensures the security infrastructure remains healthy and appropriately updated to address emerging threats.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Enhance and expand cybersecurity			
Approximate Construction Schedule:	Yearly/ongoing			
Budget Basis:	DGP and IT estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 3,500,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$250,000	\$800,000
	Material	\$ 0	\$ 50,000	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$300,000	\$800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Enhance Maximo Capabilities and Processes
Purpose and Necessity:	As DTEE increases investments in its distribution grid and focuses on automation, the higher workload and job complexity will require the company to advance its work management systems and processes. Maximo, a work management application, tracks scheduled and unscheduled work, work order creation, resource scheduling, and work execution for employees, vendors and third-party crews.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 47

(a)

(b)

Program:	Enhance Maximo Capabilities and Processes
Scope:	• Add a specific instance of our Maximo product to serve the Distribution Operations business unit. • Planned work integration with mobile tools like Field Service Edge (2025). Planned work includes preventative maintenance inspections.

(a)

(b)

Program:	Enhance Maximo Capabilities and Processes				
Benefits:	- This investment will bring more capabilities from our existing Maximo system to the front-line in the form of additional inspection forms and expanded asset information. - Information at the point-of-activity helps crews provide appropriate customer support in a safer and more efficient manner.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Enhance Maximo Capabilities and Processes			
Approximate Construction Schedule:	2025			
Budget Basis:	DGP estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 5,100,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$425,000
	Material	\$ 0	\$ 0	\$ 75,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	External Crew Efficiency
Purpose and Necessity:	The lack of visibility into work performed in the field and inability to measure foreign and contractor crew productivity are major gaps further exacerbated during major storms. The goal of this storm product is to provide insights into what work was completed and by whom.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 23

(a)

(b)

Program:	External Crew Efficiency
Scope:	Work for the MVP solution began in June 2023 and is projected to be completed in Q1 2024. The scope for a minimum viable product is focused on the development of: An end-to-end crew rostering application that would standardize qualified crew make up and the equipment used at the job site by non DTE crews, enabling development of cost benchmarking. 2024 and 2025 plans include: • Mobile application that would status and workflow all assigned work on time. • Work completed input form that would document all material used, work completed by teams in the field, give visibility on work mix, and validate invoices from non DTE crews. • Expand rostering capabilities to Baseload contractors, Secure First, Single Damage Assessors, and Damage Assessor • Expand mobile work application to Baseload contractors, Secure First, Single Damage Assessors, and Damage Assessor • Expand work completed input form to Baseload contractors, Secure First, Single Damage Assessors, and Damage Assessor • Deliver a billing app to document contractor time entries, validate work assignments, and expedite accurate invoicing. • Productivity improvements for outages include: • Enhanced functionality in URMA allow non-DTE crews to have quick access to job specific information (maps, assignments, chronology), driving improvements on patrol and restoration times. Real time job status and updates on work required will allow the Emergency Field Leaders and Regional Incident Command to take quick action to manage crews more effectively. Clear sight into crew make-up and available equipment will inform resource assignment and optimization. • Right-crew to the right job: Contractor resources are currently not optimized across restoration work type (i.e., too many contractors on smaller jobs or spending too much time on the job). Using Single outage jobs as an example, most jobs require only 2 crew members and should be completed in less than 2 hours.

(a)

(b)

Program:	External Crew Efficiency				
Benefits:	This investment will provide: • Non-DTE crews (i.e., baseload contractors, local foreign, and foreign crews) access to an app that storm emergency headquarters can use to have visibility of where the crews are located. • A more efficient method to communicate work assignments; thereby, reducing wait times on work direction. • Better quantification of the work required to complete an outage, while tracking productivity and progress information for resource allocation. • Improved allocation of cost between O&M and capital for non-DTE resources.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					x
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	External Crew Efficiency			
Approximate Construction Schedule:	2024/2025			
Budget Basis:	IT estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 5,207,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$3,966,000	\$720,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$441,000	\$ 80,000
	Total	\$ 0	\$4,407,000	\$800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	FLISR Implementation
Purpose and Necessity:	When electrical faults occur on DTE electric's system, technology is available that can combine status indications and analog fault currents to estimate the approximate location of the fault. Once located, the trouble location can be isolated and customers outside of the isolation zone can be restored, reducing the customer minutes associated to an outage. This is done by restoring customers before repairs are made and by reducing patrol time needed to find the location of the fault.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 35

(a)

(b)

Program:	FLISR Implementation
Scope:	Develop system-wide implementation plan for FLISR. Each year additional circuits will undergo FLISR operationalization and become available for use. This includes: • Database and SCADA linking work for additional telemetry to support FLISR • DPF convergence throughout the ADMS network model (eMap) • Impedance model tuning to improve fault location estimation accuracy • Develop tools and metrics for measuring accuracy • Change management to ensure that the application is used to gain the reduction in outage time and reduction in patrol time

(a)

(b)

Program:	FLISR Implementation				
Benefits:	This project supports the reduction of customer minutes associated to an outage by using the components of FLISR. This is accomplished by reducing patrol time needed to find the location of the fault (FL/Fault Location) and by restoring customers before repairs are made (using I/Isolation and SR/Service Restoration).				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	FLISR Implementation			
Approximate Construction Schedule:	2024-2028			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 29,511,779			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 3,781,791	\$ 5,486,100
	Material	\$ 0	\$ 629,998	\$ 913,900
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$4,411,779	\$6,400,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Grid Automation Telecommunications
Purpose and Necessity:	This investment will support the increasing need for communication backhaul being driven by the Distribution Automation program, which is installing thousands of reclosers and other pole top devices as well as collecting information from substation devices. Currently, many devices, such as pole-top and substation equipment, on DTE Electric’s system are either not connected for remote monitoring and control, or are connected through a communication network that has been developed in patchwork fashion over many decades. Where the communication network is available, it is frequently made up of diverse equipment and technology, such as fiber, microwave, leased phone lines, radio and other. Furthermore, much of the communication available is completed through a legacy serial point-to-point network that is less reliable than modern technologies and unable to enable remote management and smart grid functionality. Also, because the equipment that enables the current network has been installed over an extended timeframe, some of the equipment has become obsolete and spare parts are no longer available. The Grid Automation Telecommunication program is designed to address these communication gaps and to deploy a consistent channel with sufficient and reliable bandwidth to meet the current and growing requirements of a modern electrical system and to allow the deployment of the appropriate cybersecurity protocols.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 6

(a)

(b)

Program:	Grid Automation Telecommunications
Scope:	• Deploy fiber to connect critical locations on the distribution system including stations, substation, radio towers, service centers, and power plants back to the data centers to allow a high bandwidth and low latency network that provide high reliability, manageability and cyber security. • Extend the telecommunication network through a combination of supplementing the existing Wi-Fi Mesh, building fiber to existing substations sites, and establishing a telecommunications mesh network inside and around existing substations to connect relays and metering and pole top devices. • Install standardized telecommunications cabinets in or around each substation and build the telecommunications path to the substations. • Replace microwave tower transmitters and WiMAX pole top transmitters with transmitters operating on different frequencies (5G & Wi-Fi upgrade). This is required due to FCC mandated reassignment of Microwave and WiMAX frequencies to 5G cellular and Wi-Fi devices creating interference that renders existing DTEE infrastructure inoperable.

(a)

(b)

Program:	Grid Automation Telecommunications				
Benefits:	- Provides sufficient bandwidth and reliability for thousands of new smart grid automation devices - Allows for SCADA upgrades and automation - Allows for ADMS to monitor and control devices - Supports substation and pole top automation plan, DER integration, AMI enhancements - Enhances cyber security and resiliency - Forms the basis of a smart grid - Allows for greater resiliency during weather events and in cases of equipment failure - Eliminates dial-up modems for substation remote access - Enables many future use cases and technologies beyond grid devices				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Grid Automation Telecommunications			
Approximate Construction Schedule:	2022-2025: Installation and commissioning of fiber backbone to critical sites. 2024-2028: Installation of fiber routers, advanced mesh concentration points, and extension of fiber or other technologies to areas that require backhaul that cannot be sufficiently served by existing deployed technologies or currently do not have communications capability 2026-2030: Deployment of advanced wireless end points to serve last mile devices such as pole tops and AMI routers.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$18,695,796	\$12,300,000	\$10,900,000
	Material	\$1,710,470	\$3,700,000	\$3,200,000
	Other	\$939,993	\$900,000	\$900,000
	Total	\$21,346,259	\$16,900,000	\$15,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Grid Edge Insights & New Technology
Purpose and Necessity:	As the electrical system becomes increasingly interconnected with grid-interactive customer equipment—such as smart inverters, energy storage, electric vehicles (including Vehicle to Grid), demand response and load control resources, non-wire alternatives, and microgrids—the complexity of real-time grid management escalates with each new interaction of Distributed Energy Resources (DERs). These DER resources need to collaborate using interoperable communications that, while possibly local, must still interface with a central system. However, not all capabilities of DER resources can be coordinated in real time by a central system. Certain elements of DER operations, optimization, and protection have timing requirements that necessitate local intelligence. The safe, reliable, and efficient operation of these DER resources requires a distributed platform capable of taking control from and reporting information to utility backend systems such as the ADMS and future Distributed Energy Resource Management (DERMs) systems. This blend of local and remote control, along with utility and customer-owned resources, also necessitates a significant focus on cybersecurity. The investment will also implement OpenDSO and OpenFMB for interoperability and management, and it will be modular to allow deployment to any interconnection use case.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 30

(a)

(b)

Program:	Grid Edge Insights & New Technology
Scope:	• This investment aims to address the real-time interoperability, cybersecurity communications, and control of distributed resources, focusing on their interaction with local and remote control systems such as the ADMS and DERMS. • The focus is on the 'Grid Edge', where real-time optimization of local DER resources is necessary across operational and ownership boundaries. • The project will design, test, standardize, and implement cyber-secure control and communication schemes for DER resources and microgrids. • The platform will be modular, building on functionality developed in collaboration with the Department of Energy, National Labs, and other utilities facing similar DER integration goals. • It will integrate current and future standards for customer-owned DER to enable the broadest possible enablement of DER capabilities, all while maintaining a cybersecurity-first design. • The project will provide necessary support for NWA projects and DER integration projects. • Construction of gateways and testing facilities will utilize aspects of the Small Solar Testbed and the field portion of Gateway development. These will be absorbed from those projects as the scope has centralized around gateway development and testing. • Over multiple years, the platform will be iterated upon to optimize cost, reduce maintenance, and integrate new developments in the industry, DER capabilities, and standards.

(a)

(b)

Program:	Grid Edge Insights & New Technology				
Benefits:	- The Grid Edge platform will allow for safe and reliable interaction with DER resources in complex implementations where the coordinated interaction of Smart Inverters, energy storage, load control and microgrids is required. - Standardization of the platform will reduce per project costs. - The platform will also allow for simulation of DER interactions during project design phases to reduce onsite testing and provide more reliable operation of the DER solutions. - Enables all NWA projects to implement core technologies necessary for DER integration.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Grid Edge Insights & New Technology
Approximate Construction Schedule:	Project objectives are critical to support NWA programs and other DER deployments. 2022: Omega OPV1 control functionality, introduction for the HIL system and gateway testing 2023: Port Austin Phase 1 OPV2 control functionality, validation of HIL models and configuration of gateways 2024: Port Austin Phase 2 OPV3, Veridian OPV4 control functionality, inclusion of small-scale solar test bed and sensor analytics program along with field gateway deployment work from interconnection process enablement. procurement and construction for these projects is now integrated into this program. installation of 480V testbed areas and primary voltage switchgear 2025: OPV5 (ANM project) control design integration completion of DER training area, commissioning of primary voltage switchgear, integration of TDC solar into testbed capabilities, expansion of onsite solar for small scale solar testbed to allow more system simultaneous testing and interaction monitoring. 2026 and beyond: Integration of DER use cases into controls and validation of microgrid and advanced system interactions to support multi-party and multi circuit microgrids with high penetration including dynamic protection and advanced communications and monitoring and support future technology needed for wider adoption of NWAs.
Budget Basis:	Engineering Estimate
Total Cost: \1	Program investments are excluded from total project cost calculations.

(a)

(b)

Program:	Grid Edge Insights & New Technology			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,370,089	\$3,986,194	\$3,072,115
	Material	\$314,613	\$1,771,642	\$1,254,808
	Other	\$134,298	\$177,164	\$173,077
	Total	\$1,819,000	\$5,935,000	\$4,500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Hosting Capacity Enablement
Purpose and Necessity:	Hosting capacity analysis (HCA) is the amount of DER that can be accommodated without adversely impacting operational criteria such as power quality, reliability, and safety under existing grid control and operations. In addition, in Case No. U-20147, the MPSC has requested that DTEE adopt a phased implementation approach for HCA pilots. As the adoption rate of DERs on the system increases, HCA will be a critical tool for distribution planning to identify initial grid constraints. Furthermore, a hosting capacity map can give DER developers the ability to better select sites and possibly reduce interconnection applications for non-viable areas with grid constraints. However, as DTEE has noted in prior discussions and filings, HCA is not a substitute for the developer submitting an application to study interconnecting to the grid. An application to interconnect is still necessary to identify impacts caused by the interconnect and propose solutions to mitigate those impacts.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 43

(a)

(b)

Program:	Hosting Capacity Enablement
Scope:	• Technology investment is needed to achieve the maturing Hosting Capacity Analysis processes. To improve the speed in which customers can evaluate the ability to interconnect DERs with the grid, investment is required in both customer-facing and internal evaluation tools. The technology investment will include a system to store information on likelihood of system upgrades needed to support DER interconnection, as well as a visual interface that is externally facing for customers and developers to access. • To support DTEE's processes to evaluate hosting capacity at a granular level, investments in tools and integrations are needed. This will begin with tools such as EPRI DRIVE and CYME integration capacity analysis to evaluate areas with high penetration of DER. Further years will see investments to link the hosting capacity into the interconnection application portal. • Various server installation. • Software configuration and IT software development to automate manual process and reduce time for updates. • IT interface development and deployment.

(a)

(b)

Program:	Hosting Capacity Enablement				
Benefits:	- Customers able to see proactive information for their interconnection applications. - Screening and application tools improved for efficiency. - Helps DTE meet regulatory requirement.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Hosting Capacity Enablement			
Approximate Construction Schedule:	2022: Hosting Capacity Map roll out. 2023: Hosting Capacity Map update interfaces enhancements and Load Capacity map. 2024: Improve update interfaces and linkages to planning tools. 2025: Improve granularity displayed on maps. 2026: Integrate enhancements from Load and forecast Analytics program planning tool updates. 2027: Continue integration with Load and Forecast Analytics program planning tool updates. 2028: Complete integration with Load and Forecast Analytics program and refresh of maps architecture.			
Budget Basis:	High level IT estimate			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$232,214	\$280,000	\$230,000
	Material	\$ 0	\$ 50,000	\$ 50,000
	Other	\$ 20,786	\$ 20,000	\$ 20,000
	Total	\$253,000	\$350,000	\$300,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Interconnection Process Enablement
Purpose and Necessity:	DERs (distributed energy resources) are expected to be an increasingly common technology deployed on the electric grid. In particular, the DG/DS (distributed generation/distributed storage) scenario from the Distribution Grid Plan considers directionally plausible forecasts where customer-owned generation, predominantly expected to be rooftop solar PVs and storage in the form of batteries, is expected to increase in adoption throughout DTE's service territory. As the number of applications for DER increases, a critical component in providing accessibility to the grid will be to ensure that the process to connect to the distribution grid is streamlined and efficient. Enhancements to the interconnection process and technology to effectively capture and utilize information like the location, size and type of DER will help distribution planning efforts. Changes to the interconnection rules, new technology and interconnection programs require that interconnection processes adapt to accommodate requirements and capabilities as well as important record keeping and modelling information required by entities like MISO to assess the impact of distribution DER on the bulk electric system.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 29

(a)

(b)

Program:	Interconnection Process Enablement
Scope:	• Improve customer experience with application process - upgrade Power Clerk and interconnection application portal to provide seamless customer logon between sites (single sign on), implement electronic payment for applications, provide interface to transparently display application status to customer including integration with Maximo internal work tracking system for status updates. • Update software and interfaces to stay current with interconnection rules and procedures as well as new programs and new interconnection technology. • Improve internal system integrations for processing interconnection applications - system integration from planning application to planning study tool, CYME, and enterprise data lake. Automation scripts will support automated circuit analysis, application trending reporting, and project optimization opportunities. Automated screening tools will include loading, transformer size compatibility, and voltage constraints on the system, as well as verifying customer is within DTEE's service territory. • Study tools to support aggregated resources - enhance study tools, CYME and the enterprise data lake, to support emergent regulatory requirements including FERC 841 and FERC 2222. Study tools will need to evaluate aggregated resources across locations on the grid while evaluating interrelated impacts. • Streamlining of interconnection study process and screening to reduce the time to evaluate projects and approve interconnections while at the same time improving the accuracy of the simulation to detect where reliability issues may need to be corrected through interconnection related system upgrades.

(a)

(b)

Program:	Interconnection Process Enablement				
Benefits:	• Improve customer experience during the interconnection application process • reduce time to evaluate interconnections for safety and reliability impacts • Maintain reliable electric service by providing technology to study interrelated grid impacts of DER • Improve process efficiency evaluating interconnection applications as requests scale up • maintain compliance to new interconnection rules, standards and technologies				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Interconnection Process Enablement
Approximate Construction Schedule:	2022: DER Hosting Capacity Map initial development (has since been split into a separate hosting capacity program) Testing of smart inverter capabilities and evaluation of settings for power control systems, machine learning proof of concept for evaluating interconnection documentation. Electronic payment processing IT enhancements to DTE website. DER gateway engineering design and testing. 2023: Interconnection Rules Project to prepare for implementation of interconnection rules including automated PowerClerk data feeds, customer single sign on and customer service integration and changes to electronic payment processing. completion of machine learning proof of concept. Continued testing of smart inverter capabilities and DER gateway testing. 2024: 2024 moves the DER gateway, smart inverter and hardware interoperability testing and development work to the Grid Edge enablement program to allow this program to focus on interconnection enhancements that are customer facing and related to the application, study and approval processes of interconnection. 2024 activities include continuing work to implement the interconnection rules and procedures into the online PowerClerk system. Completing the required work on interconnection electronic payment processing and single sign on cybersecurity, Required Software updates to PowerClerk. 2025: Streamlining interfaces for interconnection study to automate data preparation and study processes. enabling online payment for more transactions. Automation of initial screening calculations to reduce manual evaluations and identification of conditions that require further study. Additional rules implementation work in PowerClerk and DTE energy portal. 2026 and beyond: Continued enhancements to PowerClerk to support rules, procedures, programs and technology changes in interconnections. Streamlining and automation of more aspects of study and screening. Completing remaining electronic payment and portal integration. Required PowerClerk software upgrades. Modification of systems to support new interconnection programs and requirements such as FERC222.
Budget Basis:	Engineering Estimate
Total Cost: \1	Program investments are excluded from total project cost calculations.

(a)

(b)

Program:	Interconnection Process Enablement			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,260,006	\$1,350,000	\$1,475,000
	Material	\$1,496,398	\$375,000	\$ 50,000
	Other	\$- 63,404	\$175,000	\$175,000
	Total	\$3,693,000	\$1,900,000	\$1,700,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Load Forecasting & Analytics
Purpose and Necessity:	The yearly planning process uses a suite of tools that are currently limited in their capability to analyze circuits outside of a single peak load scenario and are not configured to run multiple scenario analysis. These limitations make it difficult to study interconnection, NWA and complex planning scenarios. 'Advanced situational awareness analytics support planning system upgrade decisions. New developments in distributed generation resources, electric vehicle adoption, and energy waste reduction/demand response are requiring a change in process for distribution load and generation forecasting. The process, and thus data infrastructure, need to evolve into a more integrated and granular approach to provide accurate forecasts. These forecasts will inform the scenario-based distributed planning decisions. Implementation requires DTEE to collect data on customer adoption and propensity of future adoption for various customer-side equipment. Additionally, these upgrades are needed to maintain regulatory compliance with MISO, NERC, and MOD-32.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 42

(a)

(b)

Program:	Load Forecasting & Analytics
Scope:	• Integrate Power Runner with CYME to support time series analysis for each hour of the year and meet compliance for Interconnection minimum loading screening. • Establish multi-year delivery roadmap, improve functionality, and implement interim scripting to tie different functions together and improve the CYME gateway and scheduled study automation. • Integrate Maximo Interface data with CYME Advanced Project Manager. • Integrate Maximo Work Orders and CUs with CYME Advanced Project Manager. • Develop a reporting system for Work Order Changes. • Importing LiDAR data and historical reliability data into CYME. • Required software for TSAT, Power Runner, Cyme. • Develop python scripts to help support ADPS. • Develop a new load addition tool to track new industrial. primary, commercial, and interconnection customer loads. • Develop a program management tool which will include what customer programs and riders are on each meter. • New CYME server to support the time series analysis for each hour of the year which is part of the PR integration with CYME Dynamic Data Pull. • Required CYME software which is a critical for all planned circuit work in the capital budget. • Importing the relationships between sub-trans, substations, and circuits. • Enhancements to Power Runner in 2024. • Develop a network model interface in Power Runner. • Upgrade SEEQ to the version 61 to improve data analysis processes and make it more efficient. • Python Script to import data to create models to meet requirements stated by NERC. • Import ALA data into PSSE.

(a)

(b)

Program:	Load Forecasting & Analytics				
Benefits:	- Tools are used for all reliability, loading and system improvement projects. - Enables the capability to plan changes to the grid and analyze proposed improvements in loading, reliability, voltage, power quality and customer flexibility and enable the distribution planning process capabilities in alignment with grid modernization. - Load curve generation - 8760-hour load curves representing disaggregated usage and customer generation curves to plan for storage and other DER impacts - Planning processes to include multiple scenarios, including forecasting of DER and EV propensity across the system, with automated analysis support for planning engineers - Ability to forecast and sequence multi-year projects within the distribution planning toolset - Improved accuracy of system planning results with integration of AMI data in the planning tool sets - Automation of processes in CYME to reduce the need for manual data loads and model runs - Improving planning processes by developing a reporting system for work order changes and integrating CUs and work orders with CYME - Ability to run queries for meters on a specific project scope - Improves system performance while running 8760 loading analysis - Ability for DTE to meet MISO, NERC, and MOD32 requirements - Improves data analysis processes - Allows for modeling and analysis of the sub-transmission models				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Load Forecasting & Analytics			
Approximate Construction Schedule:	2022: CYME modules update and required Software for Power Runner 2023: CYME upgrade and Power Runner implementation, required CYME and TSAT software 2024: CYME APM, Dynamic Data pull, Interfaces and integrations, MOD32 Scripting, required SEEQ software, Power Runner Enhancements 2025: CYME Advanced Distribution Planning System deployment, MOD32 Scripting completion, Power Runner Forecasting tool 2026: CYME Advanced Distribution Planning System deployment, Power Runner required software, Forecasting tool Implementation, required CYME and TSAT software 2027: CYME ADPS roll out, required SEEQ software, Power Runner Enhancements for allocation and forecasting, 2028: Power Runner forecasting tool required software, platform integration, Interface and database modifications to adopt new network model			
Budget Basis:	IT evaluation of platform and data interfaces. Vendor estimate for toolset and 3 year advanced toolset plan.			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,017,490	\$2,025,000	\$2,025,000
	Material	\$608,920	\$1,600,000	\$2,300,000
	Other	\$214,500	\$275,000	\$275,000
	Total	\$2,840,910	\$3,900,000	\$4,600,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Maintain Compliance
Purpose and Necessity:	Maintaining compliance with MPSC, FERC, NERC and other industry regulations and orders is prudent. It is anticipated that beyond 2025 there will be a need for additional compliance requirements on several topics including but not limited to energy justice (EJ), electrification, cyber security and expanding NERC requirements. Having access to accurate, timely and complete operational data is key for compliance.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 51

(a)

(b)

Program:	Maintain Compliance
Scope:	This investment will help to implement systems capable of parsing operation data in real-time to support compliance efforts and meet industry requirements.

(a)

(b)

Program:	Maintain Compliance				
Benefits:	Investments in this area will have the benefit of reducing manual work required to develop evidence of compliance to regulatory mandates, provide a standardized method of developing the data and allow the Company to establish metrics to measure performance.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Maintain Compliance			
Approximate Construction Schedule:	2024/2028: Not started as of 1/12/24			
Budget Basis:	DGP estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 2,500,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$200,000	\$200,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$200,000	\$200,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Meter Improvements
Purpose and Necessity:	AMI/Meter Improvements project represents the capital hardware investment needed yearly to replace end-of-life devices or those destroyed in the field due to weather events or other incidental damage.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 34

(a)

(b)

Program:	Meter Improvements
Scope:	Maintain inventory of communications equipment necessary to support the AMI data transport performance.

(a)

(b)

Program:	Meter Improvements				
Benefits:	- These devices must be replaced or initially installed in order to ensure that the communications network retains the ability to cover our service territory reliably. - This investment is key to continuing to deliver the value already derived from the AMI system. - This investment allows us to continue to deliver Accurate billing, offer and account for new rate structures like Time-of-Day rates, and contributes to the timeliness of outage restoration.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Meter Improvements			
Approximate Construction Schedule:	Annual investment.			
Budget Basis:				
Total Cost: \1	The estimated project cost for this investment is \$ 9,800,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$250,000	\$250,000
	Material	\$ 0	\$1,150,000	\$1,150,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$1,400,000	\$1,400,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Microwave End of Life
Purpose and Necessity:	The Company owns and operates its own set of microwave communications installations. As the network grows from business-driven requirements we must replace aging assets as well as add components as we strengthen, tune, and optimize the system. This investment includes replacement of microwave paths, enhancements to stabilize the microwave ring, and support changes mandated by the FCC in deregulation of the 6 gigahertz (GHz) frequency. These efforts provide overall improvements to infrastructure redundancy, availability, capability, and security.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 39

(a)

(b)

Program:	Microwave End of Life
Scope:	• Design and implement new microwave backhaul (WAN) communications • Install modern dishes for tower weight reduction • Install hardware for network reliability and redundancy • Replace end of life hardware

(a)

(b)

Program:	Microwave End of Life				
Benefits:	- Improved reliability and control, alleviating dependency on third party systems - Network modernization and resiliency				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Microwave End of Life			
Approximate Construction Schedule:	2022: The Company erected a new tower in Marysville to house new 11Ghz microwave equipment that provides communication between Belle River and Marysville. In addition, we replaced a leased service link by installing a new microwave path between Hancock substation and our Wixom Pole Yard. 2023: We have completed the upgrade to a Frequency Assurance System that allows to manage interference on our existing microwaves that are still in use and are on target to complete 3 more updates to our 6Ghz equipment by year end with 5 actually complete in 2023. 2024: We have planned to upgrade the paths between Belle River Mills to Belle River as well as Northwest to Southfield to 11Ghz. 2025: We will continue these efforts through the replacement of licensed critical paths and unlicensed paths. Implementation of these replaced paths will improve quality of service, reliability, and allow the Company to release our leased telecom services and replace it with privately-owned communications.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 1,950,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 100,000	\$ 100,000
	Material	\$ 0	\$ 150,000	\$ 100,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$250,000	\$200,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Mobile Equipment Replacement
Purpose and Necessity:	Distribution Operations has thousands of mobile devices that have been deployed to our front-line workers and their leadership. These devices have a deployable lifecycle of 6 years.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 53

(a)

(b)

Program:	Mobile Equipment Replacement
Scope:	The Company plans and executes device replacements yearly on ~1/6th of those devices to keep the devices operational and secure.

(a)

(b)

Program:	Mobile Equipment Replacement				
Benefits:	- Up-to-date devices are more reliable and secure from cyber threats than older, less capable equipment. - Up-to-date systems contribute to efficient processes and work completion. - More efficient processes lead to quicker customer response times and helps shorten outage restoration times during a storm.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Mobile Equipment Replacement			
Approximate Construction Schedule:	2024: Tree Trim EOL MDT Replacement			
Budget Basis:	IT estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 16,281,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 80,000	\$280,000
	Material	\$ 0	\$801,000	\$2,520,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$881,000	\$2,800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Mobile Technology
Purpose and Necessity:	The mobile technology investment will help to enable seamless transitions between online and offline operations, providing integrated communication, including workflows, among the control room, field leaders, field crews, and supporting back-office staff. This technology encompasses mobile hardware and applications engineered for mobile access and usage.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 54

(a)

(b)

Program:	Mobile Technology
Scope:	• Outage Status App changes for Damage Assessment: Created a mechanism within the outage status application accessible by all damage assessors to record and provide information on outage events. • Vegetation Management Pilot Program: This includes pilot development, onsite training, device setup, and field user feedback/Q&A. Both platforms will be hosted by the vendors in their cloud server environments. • Service center Wi-Fi upgrade project: Upgrade current Wi-Fi Infrastructure at 13 Service Centers, TDC & Warren. It included installation of additional Wi-Fi capacity / coverage, addressed coverage issues inside the building and Reconfigured existing layout to meet updated requirements. The project also added outdoor coverage in the parking areas, truck bays and garages. • Field Service Edge (FSE) enhancements for overhead/underground field crews: Consolidated input screens, highlight of priority jobs, allows sorting and filtering to help crews focus during storms. Implemented bulk updates, ability to view all the crew's current assignments on a map, meter exchange job flow enhancements, bar code scanning for serial numbers. Added link to report of all crews working on the same circuit, data quality improvements for data collected and being sent back to OMS. • Lemur Pro license purchase: Purchase of 3-year Lemur Pro subscription renewal was completed in 2023. Lemur Pro, from Locana, is the application used by the OH/UG/PSR field resources to access the as-built maps of the electrical system.

(a)

(b)

Program:	Mobile Technology				
Benefits:	• Outage Status App changes for Damage Assessment: Provides the ability to query the data to understand the damage by area or region and make data driven decisions during a storm. • Vegetation Management Pilot Program: Ensure Tree Trim is selecting the right platform to enhance the user experience and enhance our maintenance program with new tools. • Service center Wi-Fi upgrade project: Field personnel will be able to connect to proper applications and have appropriate bandwidth to run applications and obtain data on the network. • Field Service Edge (FSE) enhancements for overhead/underground field crews: Improve the usability of the Field Service Edge (FSE) mobile app and streamline processes for the overhead ad underground crews. • Lemur Pro license purchase: Crews can see the location of their work in relation to circuits and other equipment as well as the location of other crews and contractors.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Mobile Technology			
Approximate Construction Schedule:	2022/2023: Outage status app changes for Damage assessment, Tree Trim’s Vegetation Management Software Replacement Project pilot project, Vendor timesheet enhancements – preliminary work done in 2022 and on hold until 2024, Service Center WIFI upgrade, Field Service Edge (FSE) enhancements for overhead/underground crews, and LOCANA purchase for Lemur multi-year Subscription 2024/2025: Damage Assessment Mapping Tool Enhancement. Vendor timesheet enhancements			
Budget Basis:	Distribution Grid Plan			
Total Cost: \1	The estimated project cost for this investment is \$ 10,464,491			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$3,754,960	\$487,805	\$640,000
	Material	\$190,251	\$ 12,195	\$160,000
	Other	\$1,150,270	\$ 0	\$ 0
	Total	\$5,095,481	\$500,000	\$800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Mobile Tools Expansion
Purpose and Necessity:	After the 2023 catastrophic ice storm, the Company undertook a series of actions to take advantage of system capabilities and opportunities that were never possible prior to the replacement of our outdated OMS system in February of 2023. The lessons learned during that storm and the capabilities that our new systems offered provided an opportunity to transform our ability to serve our customers quickly and safely as we restore power to them after significant storm events. Key objectives for mobile tool expansion is to enhance daily work through mobile tools that provide timely and accurate information, as well as allow quick and easy capture of critical data in the field. In addition, the enablement of point-of-activity applications that increase worker and leader time in the field.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 50

(a)

(b)

Program:	Mobile Tools Expansion
Scope:	• Every Day Daily Plan (EDDP): Integration of planned work, crew rostering, asset backup/asset health monitoring, and drip dispatching. • Outage Status App (OSA) Field Job closures: Provide a streamlined job closure process for business users.

(a)

(b)

Program:	Mobile Tools Expansion				
Benefits:	- Planning staff will be able to seamlessly integrate all crews, of all types, into flexible and timely daily plans. - Daily plans will translate directly into our OMS system which will shorten dispatch times, provide broad situational awareness and control of teams in the field, allow field teams to complete work at the point of activity, and automatically be recognized as available for a new work assignment in real-time. - Every Day Daily plan includes savings 1-1.5 hours per crew per day. - Integration of Planned Work: This places visibility of all work on the electric system (planned and trouble) into a consolidated location. - Integration of Crew Rostering: This will provide transparency for all crews and what they are working on each day. - Asset Backup/Asset Health Monitoring: Reliance on technology requires proactive and immediate troubleshooting for defects and seamless transition upon failure so our customer response experiences no adverse impact. - Drip Dispatching: With sustained job assignment time savings each morning, we need to extend this to dispatching subsequent work packages when crews become available. - Outate Status App (OSA) job closures: Currently, OSA only allows DTE employees to close out jobs, resulting in base load contractors having to reach out to dispatch to close out the jobs they work on. Proving the ability to close jobs via OSA will allow for faster processing of jobs and quicker dispatching which increases satisfaction of employees, contractors, and customers.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Mobile Tools Expansion			
Approximate Construction Schedule:	2024/2025: Outage Status App (OSA) Field Job closures, Every Day Daily Plan (EDDP)			
Budget Basis:	IT estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,800,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$1,100,000	\$800,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$1,100,000	\$800,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Adaptive Networked Microgrids
Purpose and Necessity:	Microgrid deployment and operation provides an opportunity to significantly improve reliability for customers by adding multiple cells of generation, storage, and load that can be isolated from the larger electrical system after significant weather events while repairs occur. Microgrids can also leverage Distributed Energy Resources (DER) and advancements in control technologies, including Advanced Distribution Management Systems (ADMS), to permit for increasing electrification and more optimal use of infrastructure.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Lines 26 and 27

(a)

(b)

Program:	NWA: Adaptive Networked Microgrids
Scope:	Port Austin: • Installation of a 500kW solar array • Installation of two 1MW x 4MWh batteries at two separate locations. • Add six additional sectionalizing devices along with communication and controls at each new site. O'Shea: • Six new sectionalizing devices, communication, and controls equipment. • Install one 1MW x 4MWh battery. • Overhead reconductoring and conduit/cable work is also required.

(a)

(b)

Program:	NWA: Adaptive Networked Microgrids				
Benefits:	Adaptive network microgrids create a stronger power grid with greater resilience to extreme weather conditions, improved reliability for communities, better resistance to systems-wide disturbances, variable renewable energy resources integrated at the distribution levels, and increased sustainability through energy efficient and renewable resources.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Adaptive Networked Microgrids			
Approximate Construction Schedule:	2024: Engineering Phase - 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 completed. 2025: Development Phase - 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. 2026: Deployment Phase - ANMs will be deployed in the field on two distribution circuits. 2027: Assessment Phase - With ANM deployments completed at Port Austin and O’Shea, the team will focus on monitoring the performance and benefits of the new technology.			
Budget Basis:	- Avoid further acceleration of system cable failures - Focus on aging cable through aggressive prioritization			
Total Cost: \1	The estimated project cost for this investment is \$ 18,839,166			
Rate Case Projection:		12mo.	12mo.	12mo.

(a)

(b)

Program:	NWA: Adaptive Networked Microgrids			
		01/01/23 thru 12/31/23	01/01/24 thru 12/31/24	01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 15,733	\$1,663,701	\$14,729,862
	Material	\$ 1,061	\$1,534,106	\$10,820,322
	Other	\$ 625	\$1,390,500	\$ 0
	Subtotal of Cost Breakdown	\$ 17,419	\$4,588,307	\$25,550,184
	Project Contributions	\$ 0	\$(2,608,533)	\$(13,109,827)
	Grand Total	\$ 17,419	\$1,979,774	\$12,440,357

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Battery Trailer
Purpose and Necessity:	Existing mobile generators, while functional, are not ideal due to their fuel consumption, noise, and emissions. Battery technology, despite its limited run time compared to diesel units, can be effectively used in various scenarios for both emergency and planned operations. When paired with other resources, batteries can enhance the resilience and capability of an emergency response fleet. Currently, there is no asset that can quickly and directly connect to the distribution system, but all the necessary components for such an asset are available. This necessitates the exploration and understanding of non-wire alternatives to alleviate the electrical system and optimize the use of these assets. Furthermore, a mobile unit's ability to be rapidly repurposed when it's no longer required at a location makes it cost-effective for demonstrating Non-Wire Alternatives (NWA) use cases or avoiding substantial capital investment when storage is only needed for a short duration before a permanent solution is implemented; thereby, preventing NWA assets from becoming stranded.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 10

(a)

(b)

Program:	NWA: Battery Trailer
Scope:	• Build a 1MW x 4MWh trailer-mounted mobile battery storage unit and make available for emergency and planned deployment. • Test the unit and develop documentation including required operating procedures to deploy the mobile battery in the field.

(a)

(b)

Program:	NWA: Battery Trailer				
Benefits:	• Use in place of traditional generators • Support system needs during shutdowns or maintenance • Use at substations or on circuits to reduce peak load as part of a broader NWA project				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Battery Trailer			
Approximate Construction Schedule:	2022: Design and procurement of medium voltage trailer components, controls design. Initial construction for lab integration testing of house service and medium voltage. 2023: Completion of medium voltage trailer integration and delivery of unit to TDC for testing. Creation of initial procedures. Completion of house service and continued construction of medium voltage testing capability at lab. 2024: Completion of medium voltage portable equipment testing capability at lab. Comprehensive testing of battery trailer components, control upgrades, validation of final procedures, demonstration tests and commissioning of unit for different use cases. Completion of this phase of project.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 5,491,580			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$194,403	\$1,175,000	\$ 0
	Material	\$934,007	\$1,000,000	\$ 0
	Other	\$ 62,590	\$ 75,000	\$ 0
	Total	\$1,191,000	\$2,250,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: EV Charging Demonstration at ACM
Purpose and Necessity:	EV charging will have a significant impact on the distribution system. This includes not only substantial new loads, but the opportunity to utilize vehicle-to-grid (V2G) and vehicle-to-home (V2H) capabilities. Fast charging also presents a specific challenge to distribution design as the load is high demand with extremely fast ramp rates that can produce power quality issues as well as distribution overloads. Techniques like managed charging and using energy storage to buffer the high demand have a lot of promise in mitigating the impacts of charging, but these systems require coordination between the customer, utility, and often a third-party vendor that manages the charging network. The cyber security and interoperability of these systems is still developing with many devices and systems being closed and proprietary, which makes integration difficult especially for distribution use cases where the needs are location dependent and may require granular and fast reaction to provide any benefit. Most systems are designed to reduce peak demand across a large geographic area or in response to market conditions. Systems that truly integrate with the distribution system and provide needed V2G benefits are still in the initial development stages but are rapidly coming to market and being deployed. This investment focuses on the use cases that are emerging and do not have widely available solutions.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 28

(a)

(b)

Program:	NWA: EV Charging Demonstration at ACM
Scope:	• Deploy and support various EV charging related technologies including extreme fast charging, distribution interactive managed charging, interoperable and cyber secure communication with chargers, wireless in road charging, charging management at depots, V2H and V2G interconnection validation, battery buffered charging, and modelling of EV loading and capabilities that can be deployed into the distribution system planning tools. • DTEE will continue partnership with DOE and partners to develop technologies to allow distributed charge management in a zero-trust network architecture. • DTEE will partner with Ford Corktown campus, New Lab, DOE, and DOE Partners to further understand charge management and V2G charging effects on grid infrastructure.

(a)

(b)

Program:	NWA: EV Charging Demonstration at ACM				
Benefits:	• Ability to develop monitoring and control capabilities with smart charge controls and inductive road charging to ensure reliable and secure interfaces. • Enhance knowledge of these new technologies on grid impacts. • Develop solutions for planners and customers that can support broad electrification and value of V2G use cases. • Demonstrate technologies with partners and the DOE to enable additional EV and V2G capabilities.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: EV Charging Demonstration at ACM
Approximate Construction Schedule:	2022: Completion of the Extreme Fast Charger and demonstration of solid-state transformer with commercially available vehicles. Beginning of design for cybersecure managed charging as part of EVs at Risc and demonstration of capability to the DOE at Westland TDC DER lab. Procurement and initial design for V2G fast charger at lab. Battery buffered storage testing, support of several small product evaluations, and charger interoperability testing. 2023: Initial construction of V2G fast charger at TDC lab, procurement of equipment for wide scale demonstration at Bagley for EVs at Risc, additional testing for chargers for managed charging and interoperability. Engineering and testing support for Emerging Technology Fund projects. 2024: Completion of V2G charging construction at TDC lab and beginning of V2G testing, field deployment of Gateway and EV at Risc capabilities in Corktown and beginning for testing. Engineering support for emerging technology fund projects. Testing of V2H and V2G consumer solutions for interoperability, communications cyber security and operability with other DER resources at the lab. 2025: Data gathering from widescale demonstration for EVs at Risc, V2G interoperability testing and engineering and testing support for Emerging Technology fund projects. 2026 and onward: Interoperability and cyber security testing and testing for managed charging projects, continued vehicle to grid interoperability to support new IEEE and UL standards implementation. Engineering and testing support for Emerging Technology fund projects.
Budget Basis:	Engineering Estimate
Total Cost: \1	The estimated project cost for this investment is \$ 8,702,736

(a)

(b)

Program:	NWA: EV Charging Demonstration at ACM			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,216,879	\$744,702	\$1,550,000
	Material	\$ 40,340	\$149,940	\$850,000
	Other	\$ 34,781	\$ 24,990	\$100,000
	Total	\$1,292,000	\$919,631	\$2,500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Fisher Load Relief
Purpose and Necessity:	Fisher substation was selected to implement NWA solutions and to analyze the impacts of NWA solutions for reducing load. Energy Waste Reduction (EWR) and Demand Response (DR) are the two NWAs being implemented at Fisher Substation. In addition, a Subtransmission Distribution Facility (STDF) will be constructed to relieve load. Drivers for the project include the following: Capacity: Fisher Substation is over firm by approximately 3.3 MVA (119% of firm). In addition, the two circuits served by Fisher substation exceed the 8MVA design standard for 13.2kV circuits. FISHR DC 8188 is also at 97% of its day-to-day rating.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 12

(a)

(b)

Program:	NWA: Fisher Load Relief
Scope:	Energy Waste Reduction • Residential implementation, incentives and installation labor, C&I (commercial and industrial) implementation and incentives. Demand Response • Program implementation for Smart Savers and Cool Currents, technology platform and IAC equipment upgrades. STDF • Establish STDF along same subtransmission line that feeds Fisher Substation, split DC 8188 FISHR with STDF circuit, install new cable, and conduit: ○ Reconductor approximately 7,140ft of overhead conductor to 3-636,B ○ Install 3 PTS ○ Install 1 3ph V4L recloser

(a)

(b)

Program:	NWA: Fisher Load Relief				
Benefits:	• Reduce equipment risk by providing load relief. • Provide sufficient capacity to serve existing and new customers. • Defer traditional load relief projects. • Reduce substation below firm and circuits below design limits.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Fisher Load Relief			
Approximate Construction Schedule:	2022 - Engineering 2023 - Overhead design and overhead construction 2024 - Overhead design, substation design, overhead construction, substation construction, load transfers and project closeout			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,780,241			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 14,884	\$3,514,024	\$ 0
	Material	\$164,689	\$1,009,915	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$179,573	\$4,523,938	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Omega Load Relief
Purpose and Necessity:	Omega Substation feeds the Harrison Township and Mount Clemens area. The area has seen an increase in load including load from indoor agriculture operations. The 40kV subtransmission trunk lines that feed Omega substation exceed their emergency ratings, which increases the risk of stranded load in the area. The blocking at this substation is set at 10.9 MVA. The peak at Omega substation was 16.3MVA and had over 980 hours of blocking in 2020. The system cannot handle the expected load growth without increasing the risk of stranded load and equipment overloads. This project will utilize non-wire alternatives (NWAs) to reduce loading on Omega substation and mitigate overloads on the subtransmission feeds.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 11

(a)

(b)

Program:	NWA: Omega Load Relief
Scope:	• Purchase 2 mobile batteries for Omega • Install mobile batteries on Omega Substation property

(a)

(b)

Program:	NWA: Omega Load Relief				
Benefits:	- Provides load relief at peak times. - Reduces blocking hours and the risk of stranded load.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Omega Load Relief			
Approximate Construction Schedule:	2021: Started engineering, design, and procurement. 2022: Finished design. Secured permits and start construction. 2023: Took delivery of MV trailers and battery trailers. 2024: Major equipment delivery. Commissioning and testing of equipment. Construction and procurement closeout.			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 12,795,087			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$903,462	\$ 24,836	\$ 0
	Material	\$1,550,538	\$ 2,405	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$2,454,000	\$ 27,240	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: O'Shea Energy Storage
Purpose and Necessity:	O'Shea Park in Detroit is the site of a 2MW solar array connected to Chicago Substation. The solar generation frequently exceeds circuit load, causing power to flow back through the substation. During periods where solar generation is intermittent or changing rapidly, voltage data as reported by the AMI meters indicates there is potential for small over-voltages or flickers. This project was developed to understand how energy storage could be utilized to mitigate these issues and develop a process for distribution to deploy energy storage systems and operate them for distribution support and non-wire alternatives.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 9

(a)

(b)

Program:	NWA: O'Shea Energy Storage
Scope:	• Install a 1MW /1MWh battery co-located with the solar array. • Install a communications gateway and demonstrate solar smoothing, voltage support, and coordination with the solar as well as demonstrate capabilities needed for market participation under FERC 841

(a)

(b)

Program:	NWA: O'Shea Energy Storage				
Benefits:	• Improve power quality in the area by addressing voltage instability. • Define DTE standards regarding safe and reliable operation of distribution energy storage. • Provides a template for future deploy of energy storage systems. • Demonstrates a non-wire alternative use case.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: O'Shea Energy Storage			
Approximate Construction Schedule:	2022: Below grade cable and conduit work, development of standards and procedures. Controls development with vendor. 2023: Completion of below grade work, installation of all major equipment and controls. 2024: Final connections, installation of gateway, installation of battery modules and system testing and commissioning completion of project.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,788,121			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$505,121	\$ 34,479	\$ 0
	Material	\$140,868	\$ 18,097	\$ 0
	Other	\$243,010	\$ 1,905	\$ 0
	Total	\$889,000	\$ 54,481	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Port Austin Load Relief
Purpose and Necessity:	Port Austin (PTAUS) is a 4.8kV substation with two load carrying circuits. The substation is at 124% of its firm rating and is over firm up to 60 hours per year. PTAUS DC 311 is at 108% of its day-to-day rating and exceeds the design recommendation 3MVA for a 4.8kV circuit. Customers toward the ends of the circuit experience voltage issues. The traditional investment to alleviate load in this area would be to upgrade the substation and convert portions of the circuits to 13.2kV. This program is to explore and understand non-wire alternatives to provide load relief to the electrical system. A microgrid will be formed to provide redundancy to the area and allow for testing and implementation of new applications with this technology.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 13

(a)

(b)

Program:	NWA: Port Austin Load Relief
Scope:	• Install 500kW solar • Reutilize existing 1MW x 4MWh battery from Omega • Install Viper recloser for sectionalizing the solar + storage site • Install additional Viper recloser to create a 300kVA microgrid

(a)

(b)

Program:	NWA: Port Austin Load Relief				
Benefits:	• Reduce equipment risk by providing load relief. • Substation kept below firm rating (90% of the time). • DC 311 kept below day to day rating (90% of the time). • 90% reduction in over firm duration over 3-yr. period. • Solar + storage offsets load during peak conditions thus increasing voltage within normal operating limits.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Port Austin Load Relief			
Approximate Construction Schedule:	2022: Engineering & begin design 2023: Finish design & begin construction 2024: Complete construction			
Budget Basis:	Estimates provided based on PMO Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 5,731,653			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$2,971,840	\$1,278,145	\$ 0
	Material	\$655,192	\$207,668	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$3,627,032	\$1,485,813	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Small Solar and Storage Testbed
Purpose and Necessity:	Many residential and small commercial rooftop solar interconnections are being proposed with battery storage. The MPSC has requested DTEE provide a solution to properly meter and integrate these storage solutions, while still maintaining compliance with distributed generation, net metering, and other tariffs. This investment will provide the resources to test the capabilities of numerous customer configurations in a safe and controlled environment. Also, it will serve as a training location for DTE field crews to understand various customer DER configurations, and a location evaluate new functionalities and customer products as markets and standards evolve. As the penetration of DER increases, this investment will help DTEE validate the safe and reliable connection of customer purchased products to the distribution network.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 14

(a)

(b)

Program:	NWA: Small Solar and Storage Testbed
Scope:	• Install a 30KW solar field and multiple bays with different customer configurations and hardware at TDC. • Initial setup will include Generac Power Cel Inverters, Solar Edge Inverter with LG battery and SMA micro inverters as well as power quality metering and a new service drop from Newburg circuit. • Extension of site to include an additional commercial installation setup, cybersecurity monitoring and additional test equipment and communications capability for load testing.

(a)

(b)

Program:	NWA: Small Solar and Storage Testbed				
Benefits:	- Allows for validation of behavior, interaction, and compliance of smart inverters. - Provides a safe environment to test future capabilities of customer purchase products, while also serving as a training platform for DTEE field services, engineers, and technicians. - Standards can be developed around these technologies to ensure safe and reliable operation, while maintaining compliance to evolving regulatory and industry standards. - Create new methods for monitoring and validating customer storage and load control projects.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Small Solar and Storage Testbed			
Approximate Construction Schedule:	2021: Basic site preparation and procure material, below grade work. 2022: H-frame installation and monitoring configuration, equipment setup, deployment of temporary solar and installation of first inverters and energy storage. 2023: Installation of additional inverter and storage systems that customers commonly use, additional installations for monitoring, networking, and interoperability testing. 2024 and beyond: Investments onward will be integrated into the Grid Edge enablement program; however, the scope includes additional equipment testing of energy storage and advanced inverters including V2G interactions. As well, as construction of additional H-Frames and dedicated training area.			
Budget Basis:	Engineering Estimate, vendor quotes			
Total Cost: \1	The estimated project cost for this investment is \$ 2,410,873			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$112,072	\$ 158,277	\$ 140,090
	Material	\$269,985	\$ 381,295	\$ 337,481
	Other	\$ 17,943	\$ 25,341	\$ 22,429
	Total	\$400,000	\$564,913	\$500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	NWA: Veridian
Purpose and Necessity:	Veridian at County Farm is a two-part development by Avalon and Thrive, aiming to bring a net-zero residential project to Ann Arbor. Due to the advanced technology and electrification components of this development, DTE anticipates needing to pursue a series of investments in the local distribution system. The customers are in between two RGENT circuits at 4.8 kV. Additional load causes the circuit to exceed the distribution design order limits for a 4.8 kV circuit or the day-to-day rating of the circuits. There will be two components to this project; a non-wire alternative (NWA) solution driven by the needs of Avalon and Thrive and a solution that involves reconductoring on the existing circuits. The significant amount of solar and storage the community will be installing will create an ideal environment to validate interoperable controls and communications between utility assets and customer DER. This will allow demonstration of advanced inverter capabilities and optimization of the DERs.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 25

(a)

(b)

Program:	NWA: Veridian
Scope:	RGENT PL 0009: • Replace ~6300 ft of OH conductor with 636-B • Replace ~40 poles • Remove and replace 4.8kV capacitor • Replace (1) single phase transformer • Remove and replace disconnect switch RGENT DC 0351: • Extend ~400 ft of OH conductor • Replace ~4600 ft of OH conductor with 636-B • Replace ~50 poles • Replace (4) single phase transformers TIE 1544: • Reconductor ~5000 ft of OH conductor • Replace all poles with steel poles TRUNK 1563: • Reconductor ~4200 ft of OH conductor • Remove ~1800 ft of dead wire • Replace all poles with steel poles Install utility interconnection gateway, communications, and energy storage unit, interfaces to customer DER to dispatch load and storage and optimize area energy usage.

(a)

(b)

Program:	NWA: Veridian				
Benefits:	• Reduce equipment risk by providing load relief • Provide capacity to serve new development • Defers conversion to 13.2kV • • Demonstrates integration of customer DER resources into grid optimization				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	NWA: Veridian			
Approximate Construction Schedule:	2022 - interconnection cluster study and design. 2023 - Engineering and overhead design, circuit reconductoring, engineering design for DER coordination 2024 - Engineering and overhead design, circuit reconductoring. Overhead project complete, RFP for battery storage system, work with developer on coordination of customer owned DER and where to site battery and communications and gateway equipment. development of gateway software and controls to provide cyber secure interface for DER management. 2025 - delivery of battery system, installation of battery and interconnection gateway and communication hardware. Initial testing of customer dispatchability 2026 - commissioning of battery system, integration of battery system with customer dispatchable DER and optimization of site energy in regards to grid constraints. Testing and monitoring of solution			
Budget Basis:	Project Management Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 9,921,583			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,131,269	\$1,896,145	\$561,024
	Material	\$427,986	\$550,042	\$3,426,145
	Other	\$272,765	\$200,015	\$300,013
	Total	\$1,832,020	\$2,646,202	\$4,287,182

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Operational Technology and Error Free Communication
Purpose and Necessity:	To address customers dissatisfied with unreliable restoration estimates, a lack of relevant and timely information from the Company, and the inaccurate notification of their restoration status (i.e., “power-on” when it is not), and to provide customers the level of service they expect and deserve, in 2021 the Company launched the Error Free Communication (EFC) – Outage Status initiative. The intent of this program is to fully understand the Customer experience during these types of events and to tailor our communications to those affected for customers to be able to reliably make decisions based on the information that we can supply them. Customers are frustrated because we cannot quickly and definitively determine if a customer has power. Therefore, we cannot feed that information into our workflows, and this creates errors in communication with our customers about the current state of their restoration. Additionally, we have prioritized operational efficiency over restoration data accuracy. In an effort to balance operational efficiency with customer experience this investment is addressing the following issues: • No single view of customer outage status based on all sources of information available to DTE (Customer, AMI, Equipment, Jobs, Restoration Estimate); • Currently, closing job in OMS directly translates into the incorrect assumption that customers are restored which is driving our channels to have errors (website, mobile app, outage map); • We are using AMI numbers publicly during a storm, which is inconsistent with OMS numbers on the outage map - media, poweroutage.us, and EEI are unclear of the correct number which is reducing our credibility.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 33

(a)

(b)

Program:	Operational Technology and Error Free Communication
Scope:	This program represents the near real time data processing needed to supply that information to our customer systems and is described in Witness Hatsios’s testimony, Part 6. 2023 and Prior: Premise Power Status (PPS) was developed as a stop gap solution before new Outage Management System was brought online in Feb 2023. PPS received direct feed from AMI Collection engine of current status of power according to the reported meters: YES – power on, NO – power off, or DON’T KNOW – meter is unreachable. Implementation of newly identified business rules include: • Hourly interrogation of meter population that did not have power or reported as DON’T KNOW with the previous hour. • Including JOB and RESTORATION ESTIMATE in the premise data to simplify customer communication. Incorporated business rules that would estimate power status of meter population, based on the available meter status within the same area/transformer/feeder. The following key scope items will be delivered as part of the Error Free Communications project: • For the first time, we will combine meter data (AMI), work order data, customer data and equipment hierarchy that makes up our entire grid to create single source of truth for outage data • Using the single source of truth, we will be able to validate outage data with Smart Meter Data and more accurately close jobs. 2024 and Beyond: • SOS hardening and refactoring: internal storm outage info notifications enhancements and Optimization, PPS Contingency Reads Enhancements (Q1 2024), Damage Assessment Mapping, Feeders out one stop for dispatchers and ESOC, • DO RCO Enhancement GPS Productivity: Power BI dashboard with visuals to identify key metrics including time out of the yard, time to first job and time returned to yard. Additional tool(s) to identify vehicle trip data in a layout that is easy to read, integrated data sources - Verizon Connect, MTS (Mobile Time Sheet), and eDVIR

(a)

(b)

Program:	Operational Technology and Error Free Communication
	repository (from fleet) for DO RCO, all four regions and thirteen service centers and vehicle to employee rostering. • AI/ML tools to support storm excellence: Assist in data mapping and gaps analysis, Assist with the assessment of data quality, Assist in the creation of data ingestion and processing pipelines, Design and execution of test cases • Support deep dive analysis by performing ad-hoc queries and analyzing and reporting on results, collaborate with data science to create analytical datasets, Assist in deployment planning and execution, Working data ingestion and processing pipelines as defined and prioritized by DTE, Data quality and gaps analysis report, Data flow design document

(a)

(b)

Program:	Operational Technology and Error Free Communication
Benefits:	2021, 2022, and 2023: - Upgraded Power Premise Status (PPS) logic to include Power restoration notification (PRN) in restoration decision that improved notification time. - System designed to scale dynamically – increased stability under high loads (storms) by scaling down under low load. - Added sequencing to improve accuracy of customer communications - Retriggering logic refactored in PPS to eliminate multiple repetitive premise status change communications to our customers. - Established automated contingency reads that would keep attempting scheduled reads for premises without power until restoration. - Structured equipment data to allow quick identification of premises that were tied to the device causing an outage. For work being done in 2023/2024 and beyond: This work is as important to our success in managing all storms as it represents the human interface side of our efforts. Better information, delivered in a timely manner, affords the customer a role in their restoration by ensuring that we are communicating accurately and giving them opportunities to provide us feedback during the event. These improved feedback loops and communications options allow us to take advantage of the capabilities of our ADMS systems that were brought online in 2023. 2022 Performance – With the implementation of EFC, where the customer’s power status is based on AMI data, the Company has consistently achieved a 99% accuracy rate for the customer’s power status. 2023 Performance – With the EFC enhancements implemented, the Company maintained Power Restoration Accuracy at 99%. To enhance the ability to monitor timeliness, a new metric, Restoration Communication within 1-hour, was designed after the implementation of ADMS in the first quarter. Restoration Communication within 1-hour metric concluded 2023 at 41.5%.

(a)

(b)

Program:	Operational Technology and Error Free Communication				
	2024 Forecast – The EFC enhancement implementation will maintain 99% Power Restoration Accuracy and improving Restoration Communication Sent within 1-hour to 65%. The Long-Term Target is to maintain a Power Restoration Accuracy of 99% and improve timeliness Restoration Communication Sent within 1-hour to 90%. 2024: - SOS hardening and refactoring: Resiliency- App perform under the system loads of large storms. Operational Excellence – minimize unnecessary truck rolls and have alerts in place to warn the team when system is in duress, Enhance Customer Experience optimizing the way we dispatch crews. - DO RCO Enhancement GPS Productivity: key metrics including time out of the yard, time to first job and time returned to yard., vehicle trip data, Vehicle to employee rostering. - AI/ML tools to support storm excellence: utilize data science approach to improve the accuracy of restoration time of outages and communications to customers. This project requires significant amount of efforts in data engineering and data science to ensure data in outage managements system, AMI, customer services and communications. Metrics to measure the percentage of accuracy of the first time estimate time of restoration (ETR) communicated to customers is a key metric. Due to the complexity of business processes, the metrics are categorized for storm periods and non-storms periods.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Operational Technology and Error Free Communication			
Approximate Construction Schedule:	2022/2023: Premise Power/EFC enhancements 2024/2025 projects: System Outage screen (SOS) hardening and refactoring, DO RCO Enhancement GPS Productivity, AI/ML tools to support storm excellence			
Budget Basis:	Future costs are developed using similar completed projects adjusted for the latest labor rates and material cost while incorporating the lesson learned and input from the experienced execution teams			
Total Cost: \1	The estimated project cost for this investment is \$ 21,545,014			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$130,829	\$5,100,000	\$1,300,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 4,993	\$500,000	\$100,000
	Total	\$135,823	\$5,600,000	\$1,400,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Other Modernize Grid Management
Purpose and Necessity:	Other Modernize Grid Management encompasses a diverse set of projects designed to enhance our operational capabilities, particularly during high-volume outage events. From software improvements to licensing acquisitions, each investment contributes uniquely to bolstering efficiency and resilience in our technology landscape.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 40

(a)

(b)

Program:	Other Modernize Grid Management
Scope:	Includes implementation/integration of the following: • Premise Power Status for the Error Free Customer Communications program (EFC) • OMS Downtime Procedure • Current Transformer/Voltage Transformer (CT/VT) High Voltage test console project • Increase Backhaul Capable Field Area Routers: Modification of ~500 currently installed FCN nodes to enable to operate as gateway units, as well as install 150 new gateways. • OSI License purchase • Pre-Storm-Season ADMS Enhancements • Post-Storm-Season ADMS Enhancements • Qlik 3-year license purchase • Power Awareness Device

(a)

(b)

Program:	Other Modernize Grid Management
Benefits:	Premise Power Status (PPS)/EFC is an investment supporting DO and Customer Service work. Benefits of PPS/EFC provide an enhancement of the timeliness and accuracy of customer storm restoration estimates. Enhancements in 2022 and 2023 resulted in a 99% accuracy rate for customer power status and identified the restoration communication within 1-hour metric at 41.5%. Further enhancements, through 2025, forecast the maintenance of the 99% accuracy rate for customer power status, and a move to 65% for restoration communication within 1-hour. The long-term goal for the restoration communication within 1-hour metric is 99%. The OMS Downtime Procedure allows for visualization of outages calls on a given circuit, which supports a safe and reliable response to outages and related public safety events. Current Transformer/Voltage Transformer (CT/VT) High Voltage test console project maintains DTE's capability to ensure billing accuracy compliance required by the MPSC. Furthermore, the system enables testing of high accuracy instrument transformers, which has gained momentum as the manufacturing standard for regulatory compliance. Increase Backhaul Capable Field Area Routers includes the modification of FCN nodes to enable them to operate as gateway units to increase throughput of PON and PRN messages received from meters. This will help improve throughput of voltage interval data, which is used in numerous power quality applications including Error Free Communications (EFC) and Premise Power Status (PPS). Additionally, this investment will improve throughput of billing interval data, which is more essential with the Time of Use (TOU) rate. The pilot has been completed and the results show a ~10% increase in meter messages received in test areas; this supports the projected 3-5% improvement in PON reception by increasing AMI Gateways. Overall, this solution improves accuracy and timeliness in customer communications regarding outage and restoration. OSI License purchase investment was an opportunity to purchase licenses on a 5-year term that would reduce the price of these licenses by ~\$1M over that time and shift the warranty period to cover that entire term at a fixed cost

(a)

(b)

Program:	Other Modernize Grid Management				
	rather based on time and material. The savings realized in this area will reduce the overall costs which support customer affordability. Pre/Post Storm-Season ADMS Enhancements aid in the reduction of customer outage duration. Qlik 3-year license provides near real-time outage management data to corporate applications. This near-real-time data source provides the capability for applications and reports to aggregate and visualize OMS information to improve restoration processes and restore customers quicker. Power Awareness Device investment provides the secondary pathway for DTE to hear from customer meters the power out and power restoration status over the cell network. This project will provide situational awareness for our customers and employees regarding power status at premises that would aid in restoration and help pinpoint trouble behind trouble events.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Other Modernize Grid Management			
Approximate Construction Schedule:	2022/2023: Premise Power Status/Error Free Customer Communications, OMS Downtime Procedure (targeted for completion in 2024), Transformer/Voltage Transformer (CT/VT) High Voltage test console project (targeted for completion in 2024) , Increase Backhaul Capable Field Area Routers (please refer to AMI/CPSV exhibit), OSI License Conversion (purchase completed in 2023), Pre-Storm-Season ADMS Enhancements (completed in 2023; further investment under ADMS enhancements), Post-Storm-Season ADMS Enhancements (completed in 2023; further investment under ADMS enhancements). Qlik 3-year license renewal (completed in 2023), Power Awareness Device (2023/2024 pilot- implementation targeted in 2025) 2024 Projects: Meter Failure Analytics (not started), AMI ANOC formation (not started). Completion of OMS Downtime Procedure and Transformer/Voltage Transformer (CT/VT) High Voltage test console project			
Budget Basis:	IT Estimates			
Total Cost: \1	The estimated project cost for this investment is \$ 43,418,576			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$16,874,900	\$1,980,000	\$2,250,000
	Material	\$1,423,690	\$220,000	\$250,000
	Other	\$8,112,580	\$ 0	\$ 0
	Total	\$26,411,170	\$2,200,000	\$2,500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Power Quality Analysis Program
Purpose and Necessity:	Currently, power quality meters require manual connection via a laptop on-site. Once collected data is brought back to the data center, it resides in various vendor-specific tools, making it challenging to analyze and correlate with other events. Typically, this data is only used for forensic analysis after significant equipment failures or outages, where root cause identification is crucial for system restoration. Unfortunately, a substantial amount of data remains unreviewed. To enhance the utility of existing power quality (PQ) metering solutions, we propose purchasing additional software and creating interfaces to consolidate data into a central repository for analytics. This approach will improve visibility into field devices, providing valuable engineering insights and analysis. Furthermore, these tools will facilitate long-term planning, asset health assessment, and more accurate root cause analysis for our customers. Additionally, we aim to incorporate power quality data into predictive algorithms to proactively detect issues before they escalate into outages.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 44

(a)

(b)

Program:	Power Quality Analysis Program
Scope:	• Purchase and configure Schnieder PME for Ion PQ meters • Purchase Connexo and interfaces for Honeywell meters • Implement interfaces into the SCADA tool server and ensure proper configuration and data quality establish a central repository for power quality information and interface to DTEE datalake • Develop dashboarding to provide forensic tools to engineers, so that they can make informed decisions regarding system upgrades and root cause of events. • Use machine learning to help classify and identify patterns and root causes from waveform data, which can then be feed into predictive analytics to improve outage response and potentially prevent outages before they happen.

(a)

(b)

Program:	Power Quality Analysis Program				
Benefits:	- Quick identification of root cause and patterns to inform operations and planning on arising problem areas that may not yet have outages. - Provide more insight into asset health to identify equipment issues that could lead to a failure.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Power Quality Analysis Program			
Approximate Construction Schedule:	2024: Configure Schnieder PME program on the SCADA tool servers to collect data from ION power quality meters (over 1000 customer meters and 1000 substation meters), provide dashboarding and data access to engineers and major accounts services, create historian interfaces to the system to archive events and PQ performance in real time, begin procurement of Connexo interface for honeywell meters (approximately 5000 meters) to collect PQ data, create interface to PQ meter and line sensor wave form data to bring into datalake, and conduct proof of concept evaluation of machine learning waveform identification algorithms. 2025: Complete acquisition of Connexo interfaces and integration into PQ system, develop centralized dashboard for data analysis, continue to evaluate proof of concept machine learning algorithms to determine which to implement, and create correlation capability to analyze PQ data with other outage and event data. 2026 and beyond: Enhance interfaces and dashboards and implement machine learning algorithms across the platform.			
Budget Basis:	• Avoid further acceleration of system cable failures • Focus on aging cable through aggressive prioritization			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$213,333	\$375,000
	Material	\$ 0	\$160,000	\$100,000
	Other	\$ 0	\$ 26,667	\$ 25,000
	Total	\$ 0	\$400,000	\$500,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Primary Service Orders Replatform
Purpose and Necessity:	The Primary Service Orders (PSO) application requires extensive manual processing and data entry, which negatively impacts the customer experience and level of service DTE can provide. The PSO Replatform project combines three existing systems into one consolidated system and provides automated connections to other systems that today are not connected. This new system, when fully implemented, will connect with other customer facing systems such as the customer relationship management (CRM), enterprise asset management (Maximo), and mapping systems (ESRI).
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 48

(a)

(b)

Program:	Primary Service Orders Replatform
Scope:	• Upgrade existing out of date Primary Services Web-enabled databases. • Capture and maintain detailed customer information and electronic primary operating orders. • Digitize and archive the primary customer infrastructure as-builts and sketches. • Build interfaces between the new application and supporting systems, such as customer relationship management, enterprise asset management and our mapping systems.

(a)

(b)

Program:	Primary Service Orders Replatform				
Benefits:	- This system will provide support to field resources with quick access to customer infrastructure with potential connectivity to ESRI, Maximo & C360 with up-to-date information needed to effectively support primary customer needs. - The investment will also provide an automated solution to house the primary services customer database and supporting functionality. Including the consolidation of the three applications into one application and build interfaces between the new application and supporting systems such as the customer relationship management, enterprise asset management and mapping systems.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Primary Service Orders Replatform			
Approximate Construction Schedule:	2024, 2025 and 2026			
Budget Basis:	IT estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 7,200,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$1,000,000	\$2,050,000
	Material	\$ 0	\$1,000,000	\$2,050,000
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$2,000,000	\$4,100,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	SCADA Remote Access and Configuration Platform
Purpose and Necessity:	The existing SCADA tool server is the only mechanism to remotely access and configure relays, RTU's, and other field equipment. Without this server all changes or validation of settings require a field visit. The SCADA tool server allows engineers and technicians to remotely perform many day-to-day operations to check on the status and health of devices on a detailed level far beyond the monitoring capabilities in SCADA. The existing tool server is not supported by the vendor.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 19

(a)

(b)

Program:	SCADA Remote Access and Configuration Platform
Scope:	• Provisioning of upgraded and supported hardware at downtown and alternate data center in resilient configuration • Integration of HIL Testing system • Integration of ION Enterprise PME • Configuration of PI interfaces for PQ • Configuration of PI interfaces to support increased data load • Configuration of SCADA and System Protection & Automation tools on tool server

(a)

(b)

Program:	SCADA Remote Access and Configuration Platform				
Benefits:	• Remote configuration management of SCADA devices resulting in less field visits • Immediate verification and health monitoring of assets • Centralization of power quality data from SCADA into single management platform allowing for quick and easy access				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	SCADA Remote Access and Configuration Platform			
Approximate Construction Schedule:	• SCADA remote access platform Downtown server replacement started in 2020 and completed in 2022. • ADC SCADA access server work started in 2021 and completed in 2022. • HIL testbed and PME software acquisition started in 2021 and completed in 2023. • Project was functionally completed in 2023			
Budget Basis:	Actual spend, no ongoing investments			
Total Cost: \1	The estimated project cost for this investment is \$ 2,999,171			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$114,145	\$ 0	\$ 0
	Material	\$473,217	\$ 0	\$ 0
	Other	\$ 19,608	\$ 0	\$ 0
	Total	\$606,970	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Sensor, Network and Algorithm Development (Solar Deployment)
Purpose and Necessity:	With increasing amounts of solar, storage, and other Distributed Energy Resources (DER), the ability to measure the power flows into the grid and the load consumed by customers is increasingly masked. Bidirectional energy flows, time shifting of energy, and production that offsets consumption at the same site makes forecasting load over short and long intervals very difficult unless metering is present on each resource. The lack of generation meters and high costs for real-time telemetry, like SCADA, make direct measurement impractical. With only the ability to observe an inflow and outflow meter, small solar with storage in aggregate presents a potentially large amount of load variability. Some of this variability is present due to solar and changes in cloud cover. This can be difficult to forecast even over very small time intervals and can impact system operations, especially when the grid is constrained or highly penetrated with solar and storage. This investment will help develop solutions to track and forecast solar production across many diverse resources more accurately.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 15

(a)

(b)

Program:	Sensor, Network and Algorithm Development (Solar Deployment)
Scope:	• Develop low-cost sensors. • Deploy distributed computing elements. • Evaluate a centralized machine learning platform. • Install a low-cost supplemental network of sensors. • Develop approaches and algorithms for evaluating distributed solar production in real time based on sensor inputs

(a)

(b)

Program:	Sensor, Network and Algorithm Development (Solar Deployment)				
Benefits:	The project will develop functionality in three target areas to benefit DTE customers including: • Net load forecasting • Power quality and reliability • Transformer health These will help improve the amount of hosting capacity that circuits can have by providing better insights into real time constraints and models to understand behavior of distributed systems.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Sensor, Network and Algorithm Development (Solar Deployment)			
Approximate Construction Schedule:	2022: Initial investigation of engineering solution and benchmarking of approaches, procurement of test sensors for weather and sky coverage, and procurement of hardware to provide performance testing for sensors. 2023: Development of algorithm, procurement of metering hardware and sensors, testing of weather network sensors, and selection of sensors for field deployment. 2024 and beyond: Investments onward will be represented in the Grid Edge Insights & New Technology Capital Summary, but this activity includes deploying approximately ten locations of weather network sensors widely disbursed into an area of the distribution system and then monitoring the data that is fed into the algorithm to determine the predictive capability of solar production in the area. 2025: Investments are part of the Grid Edge Insights & New Technology program but will involve continuing to monitor and evaluate the predictive capabilities of the algorithm.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 1,675,933			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$691,023	\$ 130,628	\$ 130,628
	Material	\$303,711	\$ 57,412	\$ 57,412
	Other	\$ 63,266	\$ 11,960	\$ 11,960
	Total	\$1,058,000	\$200,000	\$200,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	SOC: ASOC
Purpose and Necessity:	Though the current SOC meets minimum regulatory requirements for NERC regulated, Balancing Authority and Generator Operator tasks, managing the distribution system and recovering from a storm or other disaster from the existing backup SOC would be extraordinarily challenging and lead to slow restoration of the distribution system. The new backup SOC, also known as the Alternate System Operations Center (ASOC) will have the appropriate square footage required to collocate personnel and will have the appropriate mechanical and electrical system redundancies. In addition, the new ASOC will be outfitted with the same ADMS technology (including a video wall) as the new ESOC for seamless operations during the transition between facilities. This will allow the Company to continue the use of the electronic records of the Network Model rather than reverting to a paper version as used in the current backup facility.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 5

(a)

(b)

Program:	SOC: ASOC
Scope:	Complete design and construct an Alternative SOC site that mimic's the operations/technology of the ESOC Site at our Headquarters both in functionality and in appearance.

(a)

(b)

Program:	SOC: ASOC				
Benefits:	- Upgraded Alternative System Operations Center (ASOC) to meet industry standards - Supports faster restoration times during outages and improve system resiliency during major storms				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	SOC: ASOC			
Approximate Construction Schedule:	• Site work and building foundations completed June 2023 • Building construction to be completed March 2024 • Equipment and furniture installation and equipment commissioning, second quarter 2024 • ASOC Commissioning/ fully NERC certified and operational to be completed October 30, 2024.			
Budget Basis:	MEP Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 34,224,492			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$18,205,564	\$ 4,610,710	\$ 0
	Material	\$2,721,686	\$ 689,290	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$20,927,251	\$ 5,300,000	\$ 0

\1 The total cost is calculated using an aggregate of actual and forecasted investments, which may include investments considered for recovery through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	SOC: ESOC
Purpose and Necessity:	The System Operations Center (SOC) is the most critical facility in Distribution Operations. Personnel in the SOC operate the generation, subtransmission, and distribution systems in southeast Michigan, monitor alarms and system conditions, and direct field personnel to operate electrical elements for routine switching, risk mitigation, and outage restoration. SOC team members work with Central Dispatch personnel to ensure appropriate crews are assigned to address system issues. The current SOC poses several limitations which have been addressed by utilities DTE Electric benchmarked. Outdated facility: The facility lacks the redundancy in mechanical and electrical systems that are necessary to ensure continued operations in the event of a crisis. Outdated technology: SOC utilizes a magnetic tile representation of the electric network, as opposed to an electronic display board of the transmission, subtransmission and distribution network as is now very common in the industry. This severely limits situational awareness, which is critical at all times, but particularly during periods of crisis (for example during large storms). The current tile map board is also running out of space to accommodate growth of the system. The lack of modern technology also limits training opportunities. Space limitations: DTE Electric's SOC and dispatch personnel are currently physically separated, and their primary method of interaction is through repeated phone calls to share information and collaborate on dispatching field resources. The current SOC does not have sufficient space to achieve the co-location of these resources that manage the system and dispatch field personnel to resolve operational issues. The co-location of SOC and dispatch personnel is a well-established best practice, as it provides significant customer benefits in terms of the speed at which issues can be addressed and electric service can be restored. Limited visibility of telecommunication infrastructure performance: The reliability of telecommunication paths from field devices to the SOC is critical for the effective monitoring of the grid and for remote operations.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 4

(a)

(b)

Program:	SOC: ESOC
Scope:	• Complete design and construct primary • Complete design and construct the Smart Grid Network Operation Center

(a)

(b)

Program:	SOC: ESOC				
Benefits:	• Upgrade System Operations Center (SOC) to meet industry standards • Support faster restoration times during outages and improve system resiliency during major storms • Focused monitoring capabilities for hardware, software, network, security, endpoints, and field devices specific to the operation of the electric system through the SGNOC				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	SOC: ESOC			
Approximate Construction Schedule:	Project complete			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 100,196,813			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Substation Cybersecurity
Purpose and Necessity:	Intelligent electronic devices inside the substation offer the ability to increase safety, reliability, and operating efficiency of the grid. However, the expanding use of digital assets within substations amplifies the cybersecurity attack surface, necessitating corresponding enhancements in cybersecurity measures.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 37

(a)

(b)

Program:	Substation Cybersecurity
Scope:	This investment will be used to implement Substation Cybersecurity solutions at Stone Pool Substation. The scope includes the following solutions to correct security gaps: • Patching • HMI Anti-Virus • Special purpose devices • Alerting • Vulnerability scanning • HMI hardening • Asset and configuration management

(a)

(b)

Program:	Substation Cybersecurity				
Benefits:	- This project will provide increased asset, configuration, and password management for substation devices. - It will allow improved patching and antivirus management along with active and passive substation network monitoring and improved physical security of network access points, reducing vulnerabilities, improving threat identification and respond time, and increased ability to limit extent of an attack and more quickly restore normal operations.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Substation Cybersecurity			
Approximate Construction Schedule:	2022: Engineering and procurement was completed. 2023: Physical upgrades to substation were completed. 2024: Hardware and software upgrades will be implemented, policy and procedural changes will be implemented, and penetration testing be conducted to verify effectiveness. 2025 and beyond: Further expand to deploy standardize cyber security broadly. OH pole top cyber security will also be evaluated, designed and tested to create a set of standards for all assets deployed on the distribution system.			
Budget Basis:	Engineering Estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 4,271,312			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$1,053,082	\$380,000	\$284,000
	Material	\$239,612	\$ 0	\$100,000
	Other	\$ 46,491	\$ 20,000	\$ 16,000
	Total	\$1,339,185	\$400,000	\$400,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Substation Design Tool Upgrades
Purpose and Necessity:	The current process for designing any pole or substation work, such as updating schematics, utilizes a 2D CAD system or is not done in an electronic format. These drawings have no links to any additional data, notes and comments and are essentially text on the prints with no ability to dynamically search and update drawings. There is no automatic way to generate different views or cross sections of a design, compute structural or wind loading, requiring rework for each required design and construction drawing. There is also no automatic way to generate a bill of materials or design cost estimate from the drawings. Furthermore, capabilities are needed to automatically detect clearance and set back conflicts, to take into account high resolution site plan information and to reduce the effort needed to design and construct overhead structures, substations and upgrades to substation equipment. Guying design, wire and conduit routing must be done manually and validated through each drawing and every reference. Schematics must be manually compared to all design drawings and other schematics to ensure that reference numbers, phasing and continuity are correct. Each print must be reviewed manually and against each other to ensure accuracy of dimensions, wiring terminations and equipment position during every change. Quality control is done completely through a manual review process. While standard drawing elements are available in a library, any modification must be checked manually and any dimensional or elevation drawing must be carefully constructed each time. When working with outside design firms, multiple file conversions are needed to coordinate drawings and bring them into DTE formats. Industry tools have improved and capabilities now exist in the software to have 3D models of equipment that have relevant attributes and configurable parameters as well as physics based modelling. These sub assemblies can be placed in spatially accurate configurations and views and drawings from any angle can be generated quickly and consistently and calculations can be done for various profiles. The sub assembly parts and bill of materials can be aggregated into project level lists and interfaced with estimating systems like Maximo to order and plan the work in conjunction with the design. Vendor designs can be quickly integrated and validated through quality tools and wire and conduit routing can be checked for conflicts and clearance concerns from the same model with minimal effort. Schematic drawings are tied directly to structural and physical layouts so that the consistency checks are continuous

(a)

(b)

Program:	Substation Design Tool Upgrades
	throughout the process saving review time. Changes to standards can be propagated into new designs from the sub assembly libraries and validation of clearances and setbacks can be performed quickly for all components effected.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 45

(a)

(b)

Program:	Substation Design Tool Upgrades
Scope:	• Overhead, underground and substation design standard validation and testing to compare modelled results to actual performance • Required Software for Bluebeam, PLSCAD, SPidacalc, Bluebeam, Lidar and spatial imagery processing, RISA3d, MFAD, LPILE, Zero Turn and Substation Designer to provide planners and engineers with industry standard tools to perform calculations, validate designs and streamline work • CU creation, cell libraries and metadata for substations to standardize and streamline design and estimating • Implementation of advanced modelling capabilities and machine learning technology to improve design processes, reduce review effort and improve accuracy • Integration of structural and design tools with Maximo to streamline processes and eliminate rework and waste

(a)

(b)

Program:	Substation Design Tool Upgrades				
Benefits:	Design is performed for every overhead and substation job issued on the system utilizing tools in this investment category. Improvements to design efficiency and reducing errors contributes directly to identifying and reducing potential hazards on the electrical system and reducing the cost of design. These tools are critical for meeting requirements for implementing electrical, structural and clearance standards when projects are designed, reducing the chance of major events and increasing the resiliency of the system to withstand severe weather and operate during significant events. • Reduction in rework and improvement to consistency of designs • Validation of standards compliance of design calculations and optimization of material usage and sizing meeting structural requirements • Automatic generation of bill of materials and cost estimate framework reduces manual work and errors • Automated quality control checks and automatic cross referencing of drawings reduces review time and errors				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Substation Design Tool Upgrades
Approximate Construction Schedule:	2022 • Alternative pole material testing and validation • Overhead structural standard design testing • pole top automation structural design • Required Software for Blubeam design markup tool 2023 • Required Software for Blubeam design markup tool • Required Software for PLSCAD structural design software • Work on CU creation, cell libraries and metadata for substations (Class A) • Overhead structural standard design testing • Automated panel equipment validation proof of concept 2024 • Required software for SpidaCalc load calculation tool • Work with IT to configure platforms • Work on CU creation, cell libraries and metadata for substations (Class A, Class I, Class D) • Initial phase of microstation substation design tool platform • Required Software for RISA3D, LPile, MFAD and Zero Turn civil and structural tools • Overhead structural standard design testing • LIDAR and spatial imagery analysis tool preliminary investigation 2025 • Integration of SpidaCalc into Electric Designer tool • Integration of Electric Designer tool CUs and Maximo interface • Work on CU creation, cell libraries and metadata for substations (Class T, Class R) • Procure required software and hardware for microstation substation design tool and maximo interface • LIDAR and spatial imagery analysis tool deployment • Automated panel equipment validation tool implementation

(a)

(b)

Program:	Substation Design Tool Upgrades			
	Beyond 2025 • Complete Electric Designer integration and interfaces • Complete microstation substation designer to implement automation of cable routing and schematic wiring, clearances and 3D CAD • Completion of work on CU creation, cell libraries and metadata for substations • Procure required software and hardware to implement enhancements			
Budget Basis:	Engineering Estimate, vendor quotes			
Total Cost: \1	The estimated project cost for this investment is \$ 7,519,048			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$371,242	\$1,005,000	\$635,000
	Material	\$206,852	\$245,000	\$565,000
	Other	\$ 18,906	\$ 0	\$ 0
	Total	\$597,000	\$1,250,000	\$1,200,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Substation Reporting and Process Enhancements
Purpose and Necessity:	Maximo houses inspections and preventative maintenance (PM) of assets, work orders, job plans, material availability, purchase requisition. Without being able to combine, query and analyze Maximo, SAP, and ESRI data, critical work such as asset health and PM program tracking is a manual task.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 20

(a)

(b)

Program:	Substation Reporting and Process Enhancements
Scope:	The scope is to create new Maximo reporting tools and move existing tools contained in the "DO Reports" web application suite from outdated ASP technology to a cloud platform that is supported by IT's technology strategy. This investment will focus on Maximo queries that the engineering team prioritizes.

(a)

(b)

Program:	Substation Reporting and Process Enhancements				
Benefits:	The engineering team will have an easy-to-use set of query tools that allow teams to readily combine, query, and analyze equipment (locations and assets), work order, inspection, actual cost data and other related data from Maximo, SAP and ESRI.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Substation Reporting and Process Enhancements			
Approximate Construction Schedule:	2024			
Budget Basis:	IT estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 200,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$160,000	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 40,000	\$ 0
	Total	\$ 0	\$200,000	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Systematic Tracking of Rotatable Assets
Purpose and Necessity:	Modernization of rotatable asset (e.g., personal protective equipment) tracking through mobile technology including health and location monitoring.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 22

(a)

(b)

Program:	Systematic Tracking of Rotatable Assets
Scope:	Field tracking of assets through life cycle using RFID readers on trucks and in warehouses

(a)

(b)

Program:	Systematic Tracking of Rotatable Assets				
Benefits:	Improve the accuracy, efficiency and accountability on the movement of materials within a process.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Systematic Tracking of Rotatable Assets			
Approximate Construction Schedule:	2025			
Budget Basis:	DGP estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 600,000			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 0	\$ 0	\$600,000
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 0	\$ 0	\$ 0
	Total	\$ 0	\$ 0	\$600,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Technology Programs & NWA
Purpose and Necessity:	This program was complete in 2019. All charges since are timekeeping corrections made in error to the wrong workorder.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 16

(a)

(b)

Program:	Technology Programs & NWA
Scope:	No active scope.

(a)

(b)

Program:	Technology Programs & NWA				
Benefits:	None				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Technology Programs & NWA			
Approximate Construction Schedule:	Program completed in 2019			
Budget Basis:	Program is complete			
Total Cost: \1	Program investments are excluded from total project cost calculations.			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$ 830	\$ 0	\$ 0
	Material	\$ 0	\$ 0	\$ 0
	Other	\$ 39	\$ 0	\$ 0
	Total	\$ 869	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Tree Trim Risk Prioritization Model
Purpose and Necessity:	As the Company enters the final years of the Surge, the Company recognizes a standard 5-year cycle may no longer be optimum for the system once everything is trimmed to the same specification and considered on-cycle. The Company believes adjusting cycle-lengths based on species growth rates, risk of outages, and cost of trimming will further improve trimming efficiencies and provide reliability benefits to customers. With the acquisition of LiDAR combined with tree species data the Company has acquired over the course of the Surge program, DTE Electric has the necessary information to make data-driven improvements to the program. The Company is developing a sophisticated risk prioritization model that leverages remote sensing data (e.g., LiDAR), advanced analytics, and machine learning to estimate the probability of vegetation-driven failures and determine optimal trim cycles for an area. The Company expects that moving towards a risk-based cycle will result in trimming efficiencies and improved reliability for high-risk areas. Based on the benchmarking of other utilities, the Company anticipates the need to trim high-risk areas more frequently, and low-risk areas less frequently, resulting in an overall more efficient use of resources. In addition, more frequent trimming in high-risk areas should provide reliability benefits to customers, without sacrificing reliability in low-risk areas. Based on benchmarking and industry experts, other utilities have seen a 5% annual cost reduction related to maintenance specific trimming activities by optimizing resources and annual maintenance plan.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 17, Line 24

(a)

(b)

Program:	Tree Trim Risk Prioritization Model
Scope:	Development of a risk-model, unitization model, and outputs/reports for the Tree Trimming team.

(a)

(b)

Program:	Tree Trim Risk Prioritization Model				
Benefits:	Tree Trimming O&M savings and improved reliability for customers.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

(a)

(b)

Program:	Tree Trim Risk Prioritization Model			
Approximate Construction Schedule:	2022: Project initiation 2023: Project completion			
Budget Basis:	Costs are developed using past similar completed projects adjusted for the latest labor rates and material cost while incorporating the lesson learned and input from the experienced execution teams			
Total Cost: \1	The estimated project cost for this investment is \$ 6,901,825			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$3,491,219	\$ 0	\$ 0
	Material	\$ 8,120	\$ 0	\$ 0
	Other	\$324,971	\$ 0	\$ 0
	Total	\$3,824,310	\$ 0	\$ 0

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

(a)

(b)

Program:	Work Management & Scheduling Upgrades
Purpose and Necessity:	An effort is underway in DTE Electric to improve work management and scheduling processes to ensure field resources have the processes and tools to support the right jobs, with the right people, at the right time. This includes ensuring unscheduled work is reflected in the work management system, Maximo, and that field resources can receive information about a job's status in real-time to create a feedback loop on asset condition and performance.
Category:	Technology and Automation
Line Number:	Exhibit A-12, Schedule B5.4, Page 18, Line 49

(a)

(b)

Program:	Work Management & Scheduling Upgrades
Scope:	The current investment is being used to implement the following: • Type 2 Customer Communication & Process Efficiency - (Closed Loop) - Phase 2: Centralizing and integrating damage claims. • Contract Agreement System (CAP) Replacement: Improve the customer experience by upgrading an aging infrastructure. • Crew management enhancements: Provides more visibility related to the availability of crews and crew members. • ARCOS license renewal: The system and mobile app is used by dispatch for after-hours call outs to substation personal. • PMO Primavera upgrade and field operations tools automation: Upgrade from the current unsupported version of Primavera Scheduler used by our DO Scheduling and DO PMO Groups, and replace the interface between Primavera and Maximo with an industry standard product (e.g., Maxavera). • Field Operations Tools Automation Project: Replace existing operational tools, applications and dashboards that perform important operational control functions that no longer have the capability to support our rapidly evolving operational processes.

(a)

(b)

Program:	Work Management & Scheduling Upgrades				
Benefits:	Benefits include: • Type 2 Customer Communication & Process Efficiency - (Closed Loop) - Phase 2: Improved communication with the customer on the status of claims and support resolving damage complaints within the targeted timeframe. • Contract Agreement System (CAP) Replacement: Improves the customer experience with a more efficient contract approval system and a simplified electronic routing processes for document management. • Crew Management Enhancements: With the ability to effectively roster and deploy crews, work can be done in a timelier manner. • ARCOS license renewal: The system and mobile app is used by dispatch for after-hours call outs to substation personal. • PMO Primavera upgrade and field operations tools automation: The upgrade will bring the DO PMO group to the same version of the scheduling product as our corporate project management office is using allowing free exchange and interoperability of schedules across all DTEE. • Field Operations Tools Automation Project: For our customers, this investment will result in tighter control of field events, more information in the hands of our crews to be shared with our customers at their work locations and improved response and restoration times during outage events.				
Impact Dimension:	Reduce Electrical Hazards	Overload Relief	Capacity Relief	Regulatory Compliance	Investment in EJ Communities
Targeted:					
Impact Dimension:	Major Event Risk	SAIDI	SAIFI	O&M Avoidance	Capital Avoidance
Targeted:					

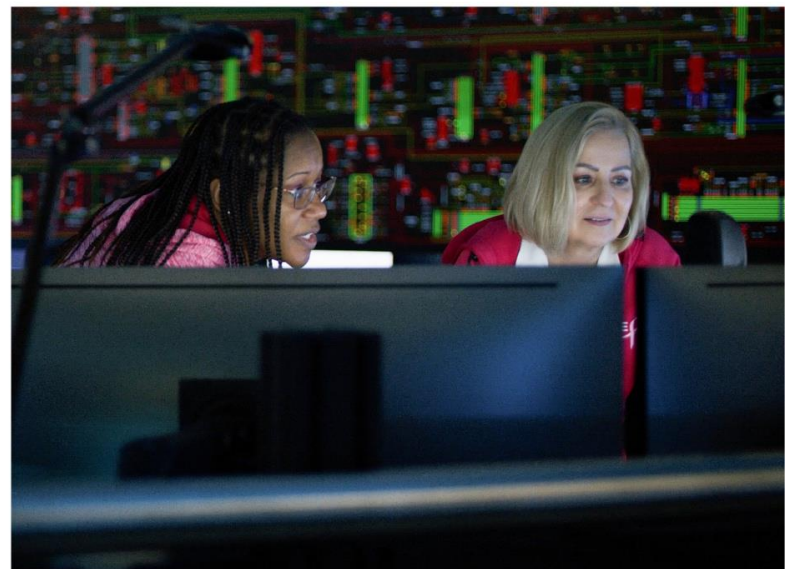
(a)

(b)

Program:	Work Management & Scheduling Upgrades			
Approximate Construction Schedule:	2022/2023: Type 2 Customer Communication & Process Efficiency - (Closed Loop) - Phase 2, Contract Agreement System (CAP) Replacement, Crew management enhancements, Multi-year Renewal license purchase for ARCOS, PMO Primavera upgrade and field operations tools automation 2024: Circuit ownership app /currently 2024 projects are being prioritized			
Budget Basis:	IT estimate			
Total Cost: \1	The estimated project cost for this investment is \$ 21,060,621			
Rate Case Projection:		12mo. 01/01/23 thru 12/31/23	12mo. 01/01/24 thru 12/31/24	12mo. 01/01/25 thru 12/31/25
	Total Labor (DTEE & Contractors)	\$3,548,232	\$632,000	\$800,000
	Material	\$133,040	\$ 0	\$ 0
	Other	\$2,834,321	\$158,000	\$200,000
	Total	\$6,515,593	\$790,000	\$1,000,000

\1 The total cost is an aggregate calculated using both actual and forecasted investments, which may include investments being recovered through the Infrastructure Recovery Mechanism.

DTE Electric Company



2023 Distribution Grid Plan

September 29, 2023
MPSC Case No. U-20147



Table of Contents

Table of Contents.....	
1 Executive Summary	6
1.1 Introduction	6
1.2 Defining the Electric Grid.....	7
1.3 Current Landscape.....	10
1.4 Future Drivers of Change	12
1.5 Investment Plan Summary	12
1.6 DGP Methodology	15
2 Planning Objectives	16
3 Future Drivers of Change	18
3.1 Scenario Planning	19
3.1.1 Electrification Scenario	21
3.1.2 Increasing Catastrophic Storm Scenario.....	26
3.1.3 Distributed Generation/Distributed Storage Growth Scenario	31
3.1.4 Scenario Impacts.....	34
4 State of the Grid	35
4.1 Current Electric System Overview	35
4.1.1 Subtransmission System Voltages	36
4.1.2 Distribution System Voltages	36
4.2 Reliability.....	37
4.2.1 SAIFI, SAIDI, and CAIDI.....	38
4.2.2 Causes of Interruptions.....	40
4.3 Distribution System Assets.....	41
4.3.1 Distribution System Asset Overview	41
4.3.2 Substation Power Transformers	43
4.3.3 Circuit Breakers	44
4.3.4 Poles and Pole Top Equipment	44
4.3.5 Three-phase Reclosers	45
4.3.6 System Cable	46
4.3.7 Underground Residential Distribution (URD) Cable	47
4.3.8 Small Wire	47
5 Gaps to Future State.....	47

5.1 Physical Grid Infrastructure	49
5.2 Observability and Controls	50
5.3 Analytics & Computing Platforms	51
5.4 Communications	51
6 Distribution Investment Strategy.....	53
6.1 DGP Investment Summary and Impact on Reliability	53
6.1.1 Investment Impact on Reliability	56
7 Pillar: Tree Trimming.....	58
7.1 Methodology of Impact Analysis.....	58
7.2 Results: Consistent Improvement Across All Metrics.....	59
7.2.1 Metric 1: Outage Events	59
7.2.2 Metric 2: Customers Interrupted	59
7.2.3 Metric 3: Customer Minutes Interrupted.....	60
7.2.4 Metric 4: Wire Down Events	60
7.3 Learning-based Improvements to Tree Trimming.....	61
7.3.1 Scheduling.....	61
7.3.2 An Industry-best Herbicide Program	61
7.3.3 Improved Efficiency Through Innovative Equipment	62
7.4 On-Cycle – Risk-Based Modeling.....	62
7.5 Accessing the Local Workforce Through Growth and Outreach	63
7.6 Conclusion	64
8 Pillar: Infrastructure Resilience and Hardening (Capital Replacement Programs)	65
8.1 Pole and Pole-Top Maintenance and Modernization Program (PTMM)	66
8.2 4.8kV Hardening Program.....	70
8.2.1 Results of the 4.8kV Hardening Program.....	71
8.2.2. 4.8kV Hardening Technical Conference	75
8.2.3 Future of the 4.8kV Hardening Program	76
8.3 System Equipment Replacement	77
8.3.1 Overhead System Equipment.....	78
8.3.2 Underground System Equipment.....	78
8.3.3 Substation Equipment.....	79
8.4 Major Event Risk	82
8.5 Programs to Address Major Event Risk	82
8.6 Short Cycle Maintenance Programs for Poor Reliability Circuits.....	84

8.6.1 Customer Excellence Program (CE)	85
8.6.2 Frequent Outage Program (CEMI).....	86
9 Pillar: Infrastructure Redesign and Modernization	87
9.1 Distribution Load Relief Projects.....	87
9.1.1 Load Relief Prioritization	90
9.1.2 Consideration of Non-Wire Alternatives	94
9.1.3 Projects to Address Distribution Loading	95
9.2 Subtransmission Redesign and Rebuild Program	96
9.2.1 Subtransmission Strategy	99
9.2.2 Scope of Subtransmission Redesign and Rebuild Projects.....	99
9.2.3 Subtransmission Prioritization.....	100
9.2.4 Subtransmission Projects and Programs	105
9.2.5 Impact of Peaking Generation on the Distribution System	105
9.3 4.8kV Conversion	107
9.3.1 Background on the 4.8kV System.....	107
9.3.2 Strategies to Address the 4.8kV System.....	111
9.3.3 Investments to Convert the 4.8kV System	111
9.3.4 Prioritization of Conversion Projects	118
9.3.5 4.8kV Conversion Plan for 2024-2028	119
9.3.6 4.8kV Conversion Plan for 2029 and Beyond	119
9.3.7 Pontiac 8.3kV Conversion	122
9.4 Undergrounding	123
10 Pillar: Technology & Automation	128
10.1 Grid Automation	133
10.1.1 Grid Automation Program	137
10.2 Operational Technology Roadmap	144
10.2.1 Grid Management Investments	144
10.2.1.1 ASOC	148
10.2.1.2 Core Grid Management	148
10.2.2 Distribution Planning Investments.....	149
10.2.3 Work Management and Scheduling Investments	154
10.2.4 Asset Management Investments.....	156
10.2.5 Mobile Technology Investments	158
11 Summary of Investment Plan	161

12 Work Prioritization	164
12.1 Investment Selection Methodology	164
12.1.1 Interruption Cost Estimate (ICE) Calculator 2.0 and the Value of Reliability.....	167
12.2 Environmental Justice	167
12.2.1 Identifying and Investing in Vulnerable Communities.....	167
12.2.2 Engaging Vulnerable Communities in Distribution Planning.....	172
12.2.3 Environmental Justice Plan and Actions	173
12.3 Tying Investments to Performance	175
12.3.1 Performance Based Ratemaking (PBR)	176
12.3.2 Infrastructure Recovery Mechanism (IRM).....	178
13 Executing the Distribution Grid Plan	179
13.1 Project Management Organization	179
13.2 Workforce Planning	180
13.3 Material and Equipment Planning.....	181
14 Storm Response	183
14.1 Mutual Assistance	183
14.2 Wire Down Response.....	185
14.3 Singles Damage Assessment.....	186
14.4 Wildfire Mitigation Approach	187
14.5 Storm Estimates and Power Status	188
15 Base Capital.....	190
15.1 Emergent Replacements	190
15.1.1 Emergent Replacement – Storm.....	190
15.1.2 Emergent Replacement – Non-Storm	191
15.1.3 Emergent Replacement – Substation Reactive.....	191
15.2 Connections, Relocations and Other	191
15.2.1 Connection and New Load	192
15.2.2 Relocation	193
15.2.3 Electric System Equipment.....	193
15.2.4 NRUC and Improvement Blankets.....	194
15.2.5 General Plant, Tools & Equipment, and Miscellaneous.....	194
15.2.6 Other Known Major Projects	194
15.2.7 Transportation Electrification Plan	195
16 IJIA Distribution Grid Activity	196

16.1 Actions and On-going Activities	197
17 Stakeholder Engagement.....	198
17.1 Customer Engagement.....	199
17.2 Community Engagement.....	202
17.3 Technical Stakeholder Engagement.....	203
Appendices	205
Appendix A State of the Grid.....	205
Appendix B Infrastructure Redesign and Modernization.....	208
Appendix B.1 Distribution Load Relief Diagram and Tables.....	208
Appendix B.2 Subtransmission Tables	217
Appendix B.3 Conversion Tables	228
Appendix C Technology and Automation	236
Appendix C.1 Grid Automation Investments	236
Appendix C.2 Grid Management Investments	240
Appendix C.3 Distribution Planning Investments	243
Appendix D Stakeholder Engagement	252
Appendix E Detroit Targeted Study	253
Appendix E.1 Area of Analysis	253
Appendix E.2 Methodology for Evaluating Substations.....	254
Appendix E.3 Findings	255
Appendix E.3.1 Completed and Planned Work.....	256
Appendix F Top 50 Strategic Capital Programs and Projects Based on GPM	258
Appendix G Distribution Plan Requirements	261
Table of Exhibits	265
Glossary.....	269

1 Executive Summary



1.1 Introduction

This is a transformational time for Michigan's electrical infrastructure. Nearly a century ago, DTE Electric¹ (DTEE or the Company) developed a grid that met customers' electricity needs when there was far less demand. Since then, the grid has expanded to developing suburbs and rural communities, but the fundamental drivers of grid change, such as load growth, have remained relatively static. That is no longer the case.

Continued investment in the grid is critical to meet the changing needs of customers, including adoption of electric vehicles (EVs), distributed generation (DG) and the evolving ways in which customers are interacting with the grid. In addition, increasingly severe weather and aging infrastructure present challenges to reliability. However, the work that has already been done to create a more resilient grid is showing strong results for our customers.

To meet customer needs into the future and to continue improving reliability, DTEE must strengthen, modernize and transform the grid. DTEE has developed a vision for the future of the grid that is driven by three essential goals:

- Increased reliability and resilience during extreme weather to ensure that the power stays on for customers during ice, snow, heat and high wind events.

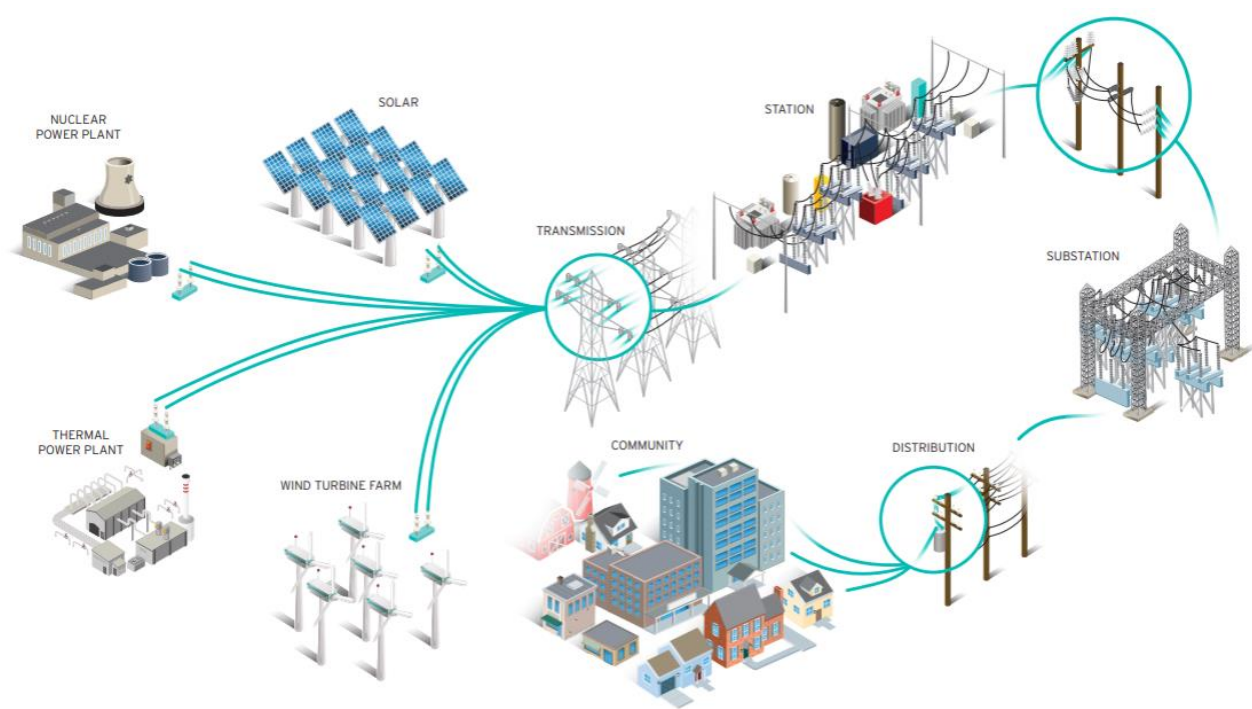
¹ DTE Electric generates, transmits and distributes electricity to 2.3 million customers in southeastern Michigan. DTE Energy, a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide, is the parent company of DTE Electric.

- Accelerated response to customer outages, driven by a smart grid that supports faster power restorations, identification and de-energization of downed wires and accurate customer restoration estimates.
- Increased grid capacity that accommodates the changing current and future energy needs of all customers.

DTEE's 2023 Distribution Grid Plan (2023 DGP or Plan) was developed to meet these goals while balancing affordability for customers.

1.2 Defining the Electric Grid

To reach customers, power travels from a generation supply resource across transmission lines to DTEE's distribution system. The distribution and subtransmission system are then responsible for delivery to destination points across the Company's 7,600 square-mile service territory. The graphic below provides an overview of how electricity moves across the entire system from generation to delivery.



Power flows to DTEE’s subtransmission stations from the transmission system at high voltage, where 230kV and 120kV² transformers at the station reduce or “step-down” the voltage to 40kV and 24kV before transmitting it via subtransmission circuits to the distribution substations across the service area. In some cases, larger substations are fed directly from the transmission network and do not use the subtransmission network. The grid is constructed this way because electrical energy is efficiently transmitted at higher voltages to minimize power losses.

DTEE currently operates 783 substations that utilize approximately 1,600 transformers. Transformers at these substations then further step-down the voltage to 13.2kV, 8.3kV, or 4.8kV and disperse it across power lines, or circuits that carry electricity to residential, commercial and industrial customers within communities. A standard single-transformer substation normally serves 1-3 circuits, while a typical two-transformer substation serves 4-8 circuits. Circuits can be constructed overhead or underground or a combination of both. Once the electricity arrives at the customer’s location, pole-top or pad-mount transformers step-down the voltage one last time so the power is delivered at a usable voltage for residences or businesses. DTEE’s distribution system includes 451,919 transformers in overhead (pole-mounted) or ground (pad-mounted) positions.

DTEE delivers power to customers utilizing 31,000 miles of overhead subtransmission and distribution lines and 14,500 miles of underground lines. A breakdown of the Company’s distribution infrastructure is shown in Exhibits 1.2.1 through 1.2.4 below.

Exhibit 1.2.1 DTEE Substations by Type and Voltage

Substation Type	Total Number of Substations	Number of Substations by Circuit/Low Side kV							
		4.8	8.3	13.2	4.8& 13.2	24	40	24 40	Other
General Purpose	542	244	4	243	30	4	13	3	1
Single Customer	145	49	0	86	1	0	0	0	9
Customer Owned	102	NA	NA	NA	NA	NA	NA	NA	NA
Total	789	293	4	329	31	4	13	3	10

² kV stands for kilovolt, or 1000 volts – 120kV is equal to 120,000 volts

Exhibit 1.2.2 DTEE Subtransmission Circuits by Voltage

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	67
40 kV	326	2,353	465	2,818
24 kV	242	177	732	909
Total	636	2,589	1,205	3,794

Exhibit 1.2.3 DTEE Transformers by Voltage Level

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	178	13,085,000
Substation - Distribution	1,449	24,093,221
Distribution - Overhead and Pad-mount	451,919	33,078,863
Total	453,546	70,257,084

Exhibit 1.2.4 DTEE Distribution Circuits by Voltage

Voltage	Number of Circuits	Overhead Miles	Under-ground Miles	Total Miles
13.2 kV	1,269	17,407	11,128	28,535
8.3 kV	13	45	18	63
4.8 kV	1,991	11,096	2,211	13,307
Total	3,273	28,548	13,357	41,905

The path electricity travels across the system is subject to interruptions due to a variety of factors (e.g., a tree falling on an overhead electrical line), which can cause outages and potentially dangerous situations for customers and employees. Electrical switches, most commonly breakers or reclosers, are in place at points along the network to recognize and isolate these interruptions (also known as electrical faults) from the rest of the distribution system. These switches allow power to continue flowing to as many customers as possible while restoration is completed for the damaged circuits.

At the distribution substation level, there are large breakers (switches) that interrupt the current flow when a fault is detected to minimize equipment damage and to isolate the faulted equipment from the rest of the system. DTEE has approximately 6,000 breakers on its distribution and subtransmission system.

Downstream from the substation breakers, located on distribution circuits, are reclosers. Reclosers perform like a breaker. When they detect faults, they open and isolate the interruption to a smaller area, impacting fewer customers. Reclosers can prevent the substation breaker from opening, avoiding a larger circuit level outage. Additionally, reclosers can be used to tie two circuits together so that, in the event of an outage, one circuit can provide power to the other. Reclosers have a key role to play in improving reliability and are the foundation of the automation program discussed in Section 10.

DTEE's distribution grid is discussed in greater detail in Section 4 below. The Company's Plan requires investments in each of the various distribution system components in order to achieve DTEE's distribution grid planning objectives (safe, reliable, affordable, clean and accessible), discussed further in Section 2 of this Plan.

1.3 Current Landscape

Aging infrastructure and worsening weather patterns have diminished the performance of DTEE's distribution grid, resulting in more frequent outages for our customers. Many of DTEE's electric grid assets are reaching, or have reached, an advanced age that requires replacement. For example, the 4.8kV system, largely installed between 1940 and 1960, is now 60 to 80 years old. The original sections of the 13.2kV system are 50 to 60 years old and are at, or near, the end of useful life.



Additionally, many of the Company's substations, circuits and "grid edge" assets (i.e., assets nearest to the customer's service site such as distribution transformers, secondary lines, service drops and underground residential distribution (URD) loops) are already experiencing high customer demand in some areas, and are not capable of accommodating the significant increase in demand that is expected to accompany electrification growth. Currently, approximately one-third of the Company's distribution substations have loading constraints, either within the substation or on its circuits. This strain on grid capacity reduces the ability to perform needed maintenance and serve new customers.

Equally important, the strain hampers restoration during outages because customer load is unable to be temporarily shifted to adjacent circuits that are already experiencing loading constraints.

The Company's 2021 Distribution Grid Plan (DGP) outlined DTEE's commitment and detailed plan to continue rebuilding and transforming the distribution grid. The progress on this plan is detailed in Exhibit 1.3.1 below. As part of this progress, DTEE has been proactive in adopting new distribution technology, including the Advanced Distribution Management System (ADMS) which provides a solid foundation on which to build additional grid technologies (discussed in Section 10).

Exhibit 1.3.1 2021 DGP Plan Key Investment Progress

Investment	Progress
Technology and Automation	- Opened the new Electric System Operations Center (eSOC) in 2022 - Launched the Outage Management System (OMS) and Distribution Management System (DMS) components of Advanced Distribution Management System (ADMS) in February 2023
Pole Top Maintenance and Modernization (PTMM)	Replaced 5,553 poles (2021-2022) through the PTMM program and on track to replace 3,353 poles in 2023
4.8kV Hardening	Hardened 677 miles of overhead circuits in the city of Detroit and on track to harden 345 additional miles by the end of 2023
Tree Trim	80% of the system is now on a five-year tree trimming cycle and the company goal is to be 100% on cycle by the end of 2025
Conversion	Energized two new 13.2kV substations in the city of Detroit (Corktown Substation and Island View Substation)

The results of recent investments are measurable,³ but to date have only benefited a fraction of the aged equipment on the electrical system; there's more work to do. These grid improvements are a step in the right direction and DTEE must continue this progress to meet the current and future needs

³ Tree trimming results are discussed in Section 7 and 4.8kV Hardening program results are found in Section 8.

of our customers. The 2023 DGP builds upon the 2021 DGP, based on learnings realized through implementation of reliability projects, as well as customer and stakeholder feedback.

1.4 Future Drivers of Change

Three external forces are fundamentally shaping the future of the distribution grid:

1. Increasing storm activity: More frequent and extreme storms and other weather events are expected to further impact electric infrastructure.
2. Electrification: As customers move away from carbon-based fuel sources there will be an increased demand for electricity to power EVs, to heating homes and businesses, and to power industrial processes.
3. Distributed Generation (DG)/Distributed Storage (DS): As more customers install solar and battery technology, the grid will be subjected to two-way power flows and the potential for increasing voltage fluctuations.



These three drivers of change are analyzed in Section 3 below to help identify investments that will address the grid needs both today and in the future.

1.5 Investment Plan Summary

Development of the 2023 DGP included incorporating data and learnings from the past two years, integrating updated information into future scenarios and evaluating feedback from customers and other stakeholders. This information drove the DGP strategy, addressing both the short- and long-term safety, reliability and capacity challenges of the distribution system.

Modernizing and strengthening a grid with more than 45,000 miles of overhead and underground circuit miles will take time and sustained investment. In response, DTEE has identified both near- and longer-term initiatives that will improve reliability for our customers. The near-term investments are projected to provide a roughly 60% reduction in customer outage minutes by 2029.

In general, the next five years (2024-2028) of investment focuses on the following overarching goals:

- Stabilize the system with equipment hardening programs to eliminate outages in the face of more frequent and extreme storms.
- Increase the level of automated restorations (smart grid technology) by adding 10,000 reclosers to the system to reduce the size and duration of customer outages.
- Continue to modernize the grid through substation and circuit voltage conversion projects and subtransmission upgrades to improve reliability by replacing end of life equipment; installing the latest automation technology, which will improve safety by eliminating energized wire-downs; and adding capacity for DER and electrification. DTEE's four investment pillars build off the work in the 2021 DGP to facilitate these goals:

1. **Tree Trimming (Section 7):** Historically, two-thirds of the time customers spend without power is due to falling trees and limbs. DTEE has ramped up the Company's tree trimming work over the last five years in response to this challenge. With more than 1,200 tree trimmers⁴ and more than an \$800 million investment since 2019,⁵ the Company has trimmed approximately 25,000 miles of reclaim trees in the last five years – 80% of total system overhead miles of trees. Our goal is to have all 31,000 circuit miles of DTEE's overhead wires fully trimmed to Enhanced Tree Trimming Program (ETTP) specifications and on a five-year trim cycle by the end of 2025. Section 7 of this Plan discusses the company's tree trimming plans and the various improvements made to the program since 2021, including the use of new and specialty equipment to trim trees in areas that pose access challenges, like backyards and alleyways.
2. **Infrastructure Resilience and Hardening (Section 8):** Replacing and upgrading existing infrastructure – such as poles, crossarms, transformers and substation equipment – continues to improve the safety, reliability and resilience of the electric grid. There are two initiatives within this pillar that will provide significant improvements to reliability. The first initiative is enhancing quality, scope and resources of the Pole Top Maintenance and Modernization (PTMM) Program. The PTMM program involves testing of poles and pole top equipment to determine condition, including the need for replacement. If equipment fails testing, it is replaced with equipment designed to a higher, stronger standard. The

⁴ On average – actual number fluctuates seasonally.

⁵ \$800 from 2019 through 2022.

Company plans to significantly increase the level of investment in this program and has a goal to reach a 10-year cycle time in line with industry standards, dramatically reducing damaged and defective poles and pole top equipment on the system. The second initiative is the completion of the 4.8kV Hardening Program in the city of Detroit in 2026. This program is focused on replacing all poles that fail inspection and all pole top equipment on the 589 miles yet to be hardened within the city. Abandoned arc wire from the former Detroit Public Lighting Department is also removed during this process. Upon completion of the 4.8kV Hardening Program, all overhead circuits in the city of Detroit will be hardened, converted to a higher voltage or in the conversion process. This work will dramatically improve reliability throughout the city of Detroit.

3. **Infrastructure Redesign and Modernization (Section 9):** One third of DTEE's distribution system was built before 1965 and can no longer meet the growing trend of electrification or customer reliability expectations. The Infrastructure Redesign and Modernization pillar focuses on converting the outdated 4.8kV ungrounded system to a more modern 13.2kV grounded system, improving safety and reliability while providing additional capacity for EVs and DG/DS. Conversion includes rebuilding large portions of the system, and the Company will analyze and consider moving wires underground as part of the process. An investment of more than \$500 million into the subtransmission system over the next five years will also eliminate many system loading constraints and provide reliable power for our customers. More details on DTEE's plans to continue implementation of this program are provided in Section 9 of this Plan.
4. **Technology and Automation (Section 10):** The increasing complexity of the grid requires additional investment; DTEE will invest more than \$1.2 billion in smart grid technology, including reclosers, through 2028. A more sophisticated smart grid will provide increased visibility of system conditions to our Electric System Operations Center (ESOC), reduce the size of outages and increase the speed of restoration for customers experiencing outages. Additionally, installing reclosers on the 4.8kV system will improve safety by increasing the ability to detect and de-energize downed wires quickly and remotely. Over the last several years, the groundwork has been laid for the transition to a smart grid. A new, world-class ESOC and the recently launched Outage Management

System (OMS) and Distribution Management System (DMS) components of the Advanced Distribution Management System (ADMS), provide the foundation needed for the installation of equipment that will automatically isolate system damage and reroute power to minimize the scope of outages. The Company plans to fully automate the distribution grid by the end of 2028. The company will also pursue additional Information Technology (IT) and Operational Technology (OT) investments supporting grid management, distribution planning, work management and scheduling, asset management and mobile technology.

These four pillars represent the focus areas that are foundational to improving safety, reliability and building the distribution grid of the future. DTE Electric has invested \$5 billion in the electrical grid over the past five years and, over the next five years, plans to invest an additional \$9 billion in making it safer and more reliable for customers.

The projects and programs that make up these investment pillars and the implementation of each of the pillar areas were identified after listening to feedback from customers and stakeholders. That feedback included a shift to consider environmental justice (EJ) in DTEE's investment decisions so that projects benefiting our most vulnerable customers are considered in the investment prioritization process. More details on the changes to DTEE's incorporation of EJ in its Global Prioritization Model (GPM) are included in Section 12 of this Plan.

1.6 DGP Methodology

To create the 2023 DGP, DTEE followed the five-step methodology used in the development of the 2021 DGP:



- **Define DTE Objectives:** Review defined objectives from the Company's 2021 DGP and align them to the long-term distribution grid vision (Section 2)

- **Assess Future Drives of Change:** The future drivers of change that are expected to have a significant impact on the distribution grid over the next five to fifteen years were reviewed, including previously identified scenario sign-posts (Section 3)
- **Assess Current State:** Assessing the current grid and its capabilities to determine how well it supports current and future customer demands (Section 4)
- **Determine Gaps to Future State:** Identify future state objectives (Section 5) based on future drivers of change, current state assessments and distribution grid gaps
- **Develop Investment Plan:** Based on those gaps, a five-year investment plan was developed, organized within the four pillars of investment (Sections 6-10). Individual program and project prioritization within the investment plan is done through the Company's Global Prioritization Model (GPM) process (Section 12)

Additionally, customer and stakeholder feedback were integrated into the Plan, including a shift to consider environmental justice (EJ) in DTEE's investment decisions so that projects benefiting our most vulnerable customers are considered in the investment prioritization process. More details on how EJ was incorporated into the GPM are included in Section 12.

2 Planning Objectives



To create a 2023 distribution grid plan aligned to the DTEE vision, the five planning objectives shared across the DTEE organization, including integrated resource planning (IRP) (see Exhibit 2.0.1), were reviewed, with specific references related to the distribution system.

Exhibit 2.0.1 DTEE Organizational Planning Objectives



SAFE

Build, operate and maintain the distribution grid and generation fleet in a manner that ensures public and workforce safety, operational risk management and appropriate fail-safe modes and is compliant with state and federal requirements



RELIABLE AND RESILIENT

Build, operate and maintain the power system within acceptable standards to withstand sudden disturbance or unanticipated failure of elements. Ensure the grid and diverse generation resources are integrated, with secure supply resources, and can quickly recover from high impact, low frequency events



AFFORDABLE

Provide efficient and cost-effective service along with diverse and flexible generation resources by optimizing the system and benefiting all customers



CUSTOMER ACCESSIBILITY AND COMMUNITY FOCUS

Provide flexible and accessible technology and grid options, and information that empowers and engages customers. Provide effective and timely communication with customers and stakeholders. Favor plans that support the diversity of Michigan communities, suppliers and workforce



CLEAN

Build, operate and maintain the resource fleet and grid platforms in an environmentally sustainable manner by achieving low carbon aspirations and clean -energy goals. Provide a grid that facilitates a transition to a decarbonized economy

1. Safe
 - a. Reduce/eliminate live wire downs
 - b. Reduce equipment failures
2. Reliable and Resilient
 - a. Reduce the number of outage events on the system to improve customers experience
 - b. Reduce the size and duration of outages to limit the impact on customers
3. Affordable
 - a. Maintain and rebuild the system in a cost-effective manner that keeps customer rates affordable
 - b. Reduce storm/trouble costs and redirect those funds into system improvements
4. Customer Accessibility and Community Focus
 - a. Ensure adequate future capacity on the system to facilitate DER and EV technology
 - b. Provide equitable investment in vulnerable communities to reduce electric reliability impact
5. Clean

- a. Build a robust and reliable distribution grid to facilitate clean generation and transportation electrification technologies

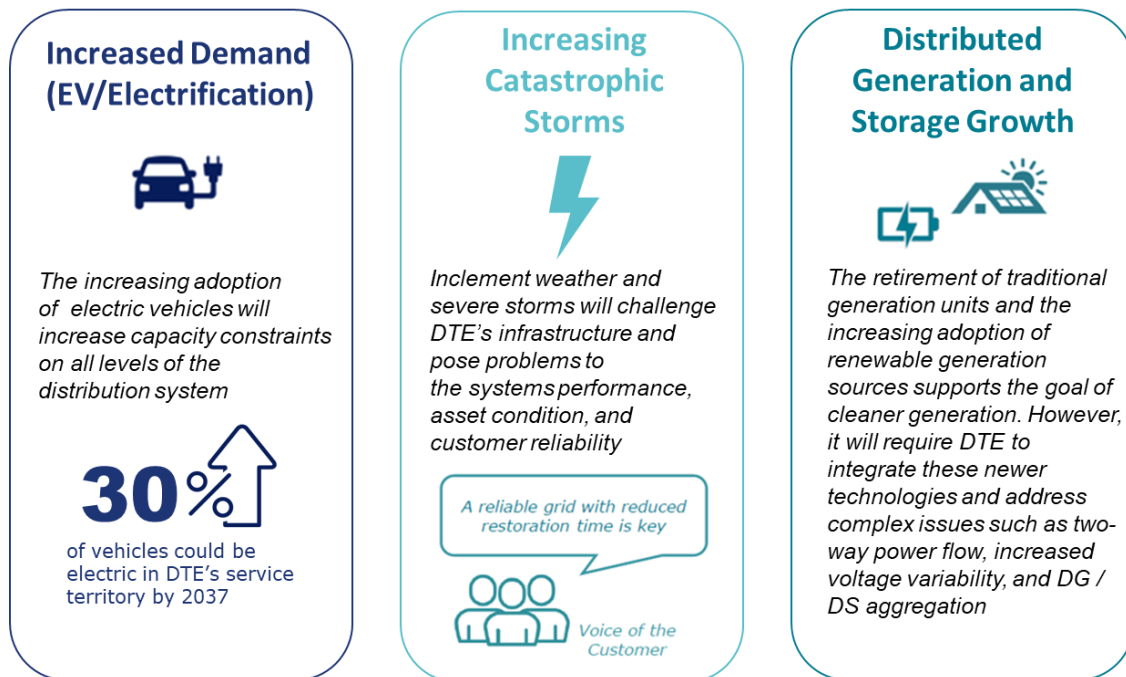
These planning objectives inform the Company's distribution investment decisions, while supporting customer expectations for cleaner and more reliable energy, Michigan's sustainability goals and DTE Electric's corporate goals for clean energy and decarbonization. Each project or program in this plan (detailed in the four strategic investment pillars covered later in the document), aligns to one or more of the planning objectives.

3 Future Drivers of Change



Customer and other stakeholder needs will continue to evolve in the coming decades and will drive a fundamental shift in demands on the electric grid. The key factors driving the grid evolution include electrification of vehicles and buildings, increasing catastrophic storm events driven by more frequent and extreme weather and the growth of Distributed Generation/Distributed Storage (DG/DS) within the distribution system. While these drivers of change pose unique challenges, they also provide DTEE an opportunity to adapt to customers' evolving needs by reshaping the distribution system into a more reliable and resilient grid that provides more value to our customers. These drivers are further detailed in Exhibit 3.0.1 below.

Exhibit 3.0.1 - Future Drivers of Change for the Electric Grid



3.1 Scenario Planning

DTEE began using distribution scenario planning in the 2021 DGP to understand the potential grid impacts caused by EV adoption, increasing extreme weather and Distributed Generation/Distributed Storage (DG/DS) integration. This section describes the updates to the scenario planning process and analysis. As in the 2021 DGP, DTEE has chosen three plausible scenarios to measure against its plans. Each scenario, shown below in Exhibit 3.1.1, represents a unique set of circumstances that have the potential to impact the grid over the next 15 years:

Exhibit 3.1.1 - DTEE Grid Modernization Scenarios

Scenario	Description
 Electrification	High electrification of transportation, buildings, and industrial processes
 Increasing CAT Storm	Increased frequency and intensity of catastrophic (CAT) storm threats to electric infrastructure
 DG/DS	High adoption of distributed generation (DG) solar PV and distributed storage (DS) as batteries behind the meter (BTM)

DTEE has identified a directionally plausible forecast specific to each scenario (e.g., increased load from electrification), along with associated grid impacts and signposts. A plausible forecast does not represent DTEE's prediction or specific forecast of the future. The plausible forecast represents a future where the drivers of the scenario experience aggressive growth and have the potential to act as a stress test on the grid. The purpose of a plausible forecast is not to predict with specificity the numerical values of drivers within that scenario, but to provide the Company with an opportunity for analysis, and the chance to study the stresses that each scenario produces on the distribution system. Distribution planning looks for specific types of investments to mitigate specific grid impacts, as opposed to an economic model of optimized solutions. These grid impacts determine future grid needs which are then analyzed in the context of the Distribution System Platform (DSPx) framework discussed below in Section 5. The resulting grid impacts illustrate how a scenario may impact grid infrastructure in its current condition. Signposts are variables that may change over time and are included in each scenario, such as technological innovation or changes in growth, cost or regulatory demands. Signposts are updated as they become known or more data is collected to allow the Company to adjust strategy if there are significant changes to forecasted scenarios.

The approach to scenario development has been updated for the 2023 DGP. A core focus of the update was increasing the alignment between the Integrated Resource Plan (IRP) that was filed in November 2022 and the Distribution Operations (DO) planning processes. To achieve this increased

alignment, forecast sensitivities⁶ from DTEE's 2022 IRP filing were incorporated as the plausible forecasts for the electrification and DG/DS scenarios and used to determine the associated grid impacts. Along with this change, the Company updated and assessed signposts and key uncertainties to understand how the drivers of each scenario may progress into the future.

The three scenarios used in longer-term distribution planning are different in intent and outputs than the scenarios and sensitivities used in the IRP. IRP scenarios forecast an optimized solution for the forecast inputs, which are typically broad market assumptions like commodity prices, technology costs, load growth and environmental regulations. In contrast, the scenarios developed for long-term distribution planning use a "plausible" forecast that represents a possible future of that discrete scenario. The three discrete scenarios are used to determine a wide range of potential future impacts to the grid, and in turn, identify gaps where grid planning or operational capabilities may need to evolve. By analyzing the grid impacts in each discrete scenario, as opposed to a combined scenario, the overall goal of scenario-based distribution planning is accomplished by identifying investment areas that address grid impacts arising in multiple scenarios. This approach ensures that identified investment areas will be needed even if the grid impacts of one scenario do not materialize or are less than anticipated. This is described in further detail in Section 5, Gaps to the Future State.

3.1.1 Electrification Scenario

The electrification scenario focuses primarily on the electrification of transportation.⁷ Under the electrification scenario, the increased movement toward decarbonization assumes a high rate of residential EV adoption and partial electrification of vehicle fleets; these shifts will have the effect of increasing electric system load.



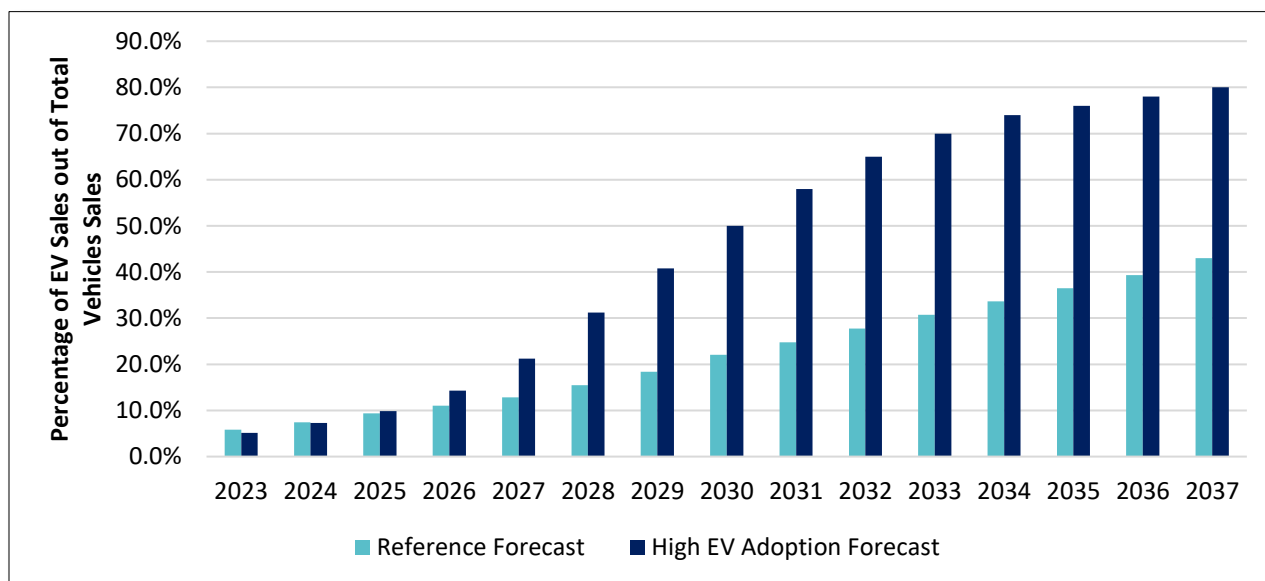
As of December 2022, there were an estimated 31,000 EVs in DTEE's service territory. Automotive industry forecasts are planning for rapid EV sales growth in the coming years, adding pressure on

⁶As described in DTE's 2022 IRP filing, different forecast sensitivities were developed to manage uncertainties and explore a range of higher and lower sales and peak demand levels. The electrification scenario incorporated the stakeholder forecast sensitivity, while the DG /DS scenario used the aggressive customer-owned distributed generation forecast sensitivity.

⁷ The electrification of transportation is expected to have a larger impact on the localized grid than the electrification of buildings. For this reason, the electrification scenario is mainly concerned with the increasing adoption of electric vehicles within DTEE's service territory.

the grid's ability to serve the additional load. While the Company believes the 2022 IRP reference forecast⁸ is most plausible, a high EV adoption forecast was used for the electrification scenario to stress test the grid impacts if EV growth accelerated more quickly than predicted. In the high EV adoption forecast, light duty EV sales will account for 80% of the light duty⁹ vehicle sales by 2037 and total EVs on the road will increase to 2,189,000 in 2037, or 64.4% of the vehicles on the road in DTEE's service territory¹⁰ A more detailed breakdown of projected sales and penetration of light duty EVs is provided below in Exhibits 3.1.1.1 and 3.1.1.2. The EV specific electric consumption will grow to 8,204 GWh by 2037. Projected growth in energy consumption is detailed in Exhibit 3.1.1.3. The high EV adoption forecast is aligned with the MI Healthy Climate Plan and assumes 50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales are electric by 2030.

Exhibit 3.1.1.1 - Light Duty EV Sales as a Percentage of Total Vehicle Sales (2027 – 2037)



⁸The reference forecast from DTE's 2022 IRP filing most closely matches the Company's internal planning assumptions, forecast and goals/aspirations. In the reference forecast, light duty EV sales are expected to be 43.0% of the total vehicle sales by 2037; total EVs' on the road will increase to 1,023,000 in 2037, or 30.1% of the vehicles on the road in DTEE's service territory. The EV specific electric consumption in DTE's service territory will grow from 165 GWh in 2023 to 3,829 GWh in 2037.

⁹ EV light duty includes residential home, public L2 and DC fast charging vehicles. EV fleet is exclusively medium and heavy-duty vehicles.

¹⁰ Assumes a base of 3.4 million light duty electric vehicles in DTE's service territory.

Exhibit 3.1.1.2 - Count of EV Light Duty Vehicles with EV Penetration (2027 – 2037)

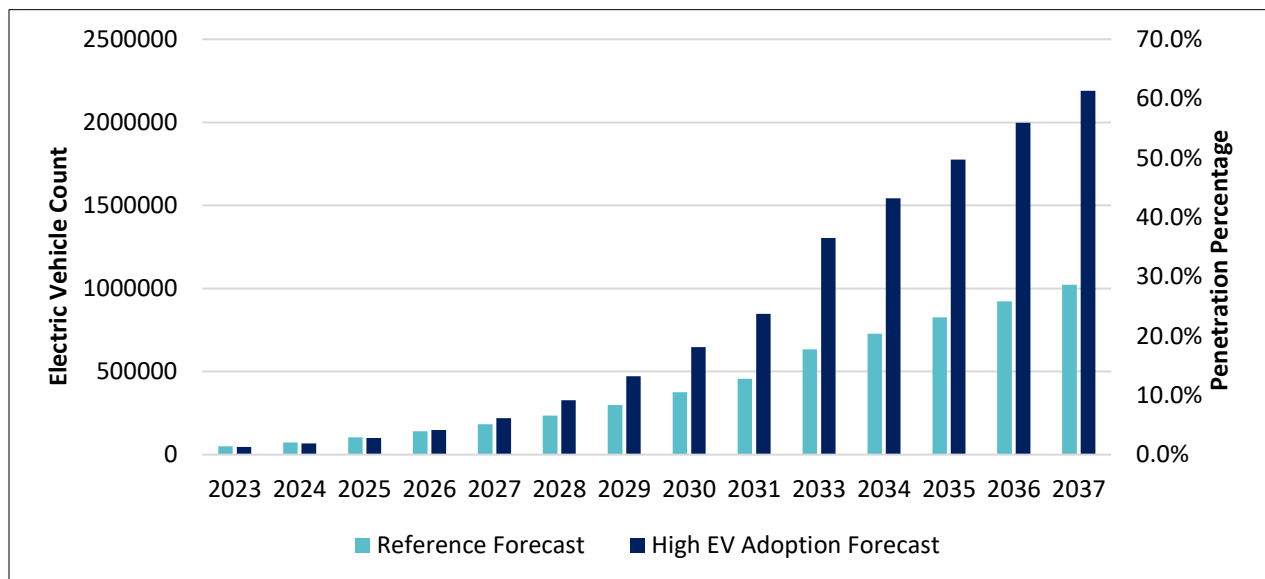
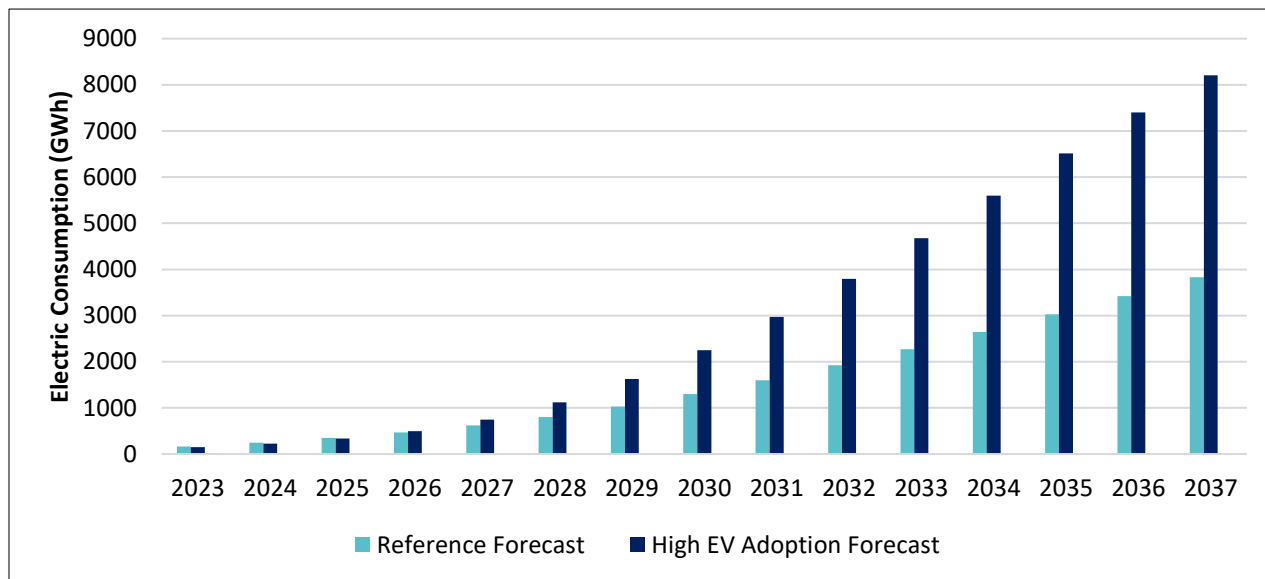


Exhibit 3.1.1.3 - Light Duty Electric Vehicle Energy Consumption (2027 – 2037)



Under the high EV adoption scenario, DTEE’s distribution system would face increasing capacity constraints, with some areas seeing higher EV adoptions earlier than other areas. While EVs will increase loading on all levels of the distribution system, the effects of EV adoption will first impact DTEE’s grid edge assets, such as underground residential primary (URD) loops, service transformers

and the secondary system. This is due, in part, to the tendency of electric vehicles to occur on the system in clusters, which results in high penetrations of EVs in a relatively small geographic area (e.g., neighborhood) or subsection of a circuit. The impact of increased adoption will gradually work upstream to trigger circuit or substation level investments as more neighborhoods on a circuit also adopt EVs. The electrification of EV fleets will also impact circuits and substations, given their substantial and concentrated electric loads. A summary of the high EV adoption load forecasts and percentage of peak load for light duty and fleet electric vehicles is shown in Exhibit 3.1.1.4. Below that, Exhibit 3.1.1.5 shows the portion of total customers on substations that are currently over their firm rating¹¹ in the high EV adoption forecast.¹²

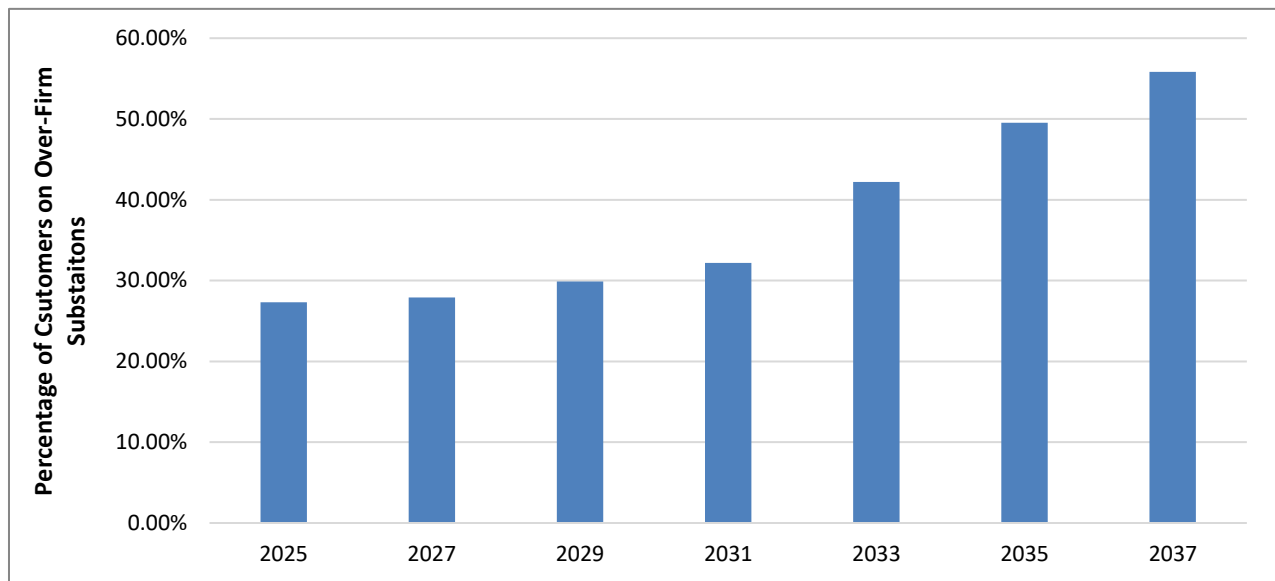
Exhibit 3.1.1.4 - Electrification Scenario Forecasts of Load Increases (2027 - 2037)

Key Drivers	2027	2032	2037
EV Light Duty	105 MW (0.95% peak)	614 MW (5.35% peak)	1,703 MW (13.7% peak)
EV Fleet	7.4 MW (0.07% peak)	39 MW (0.34% peak)	106 MW (0.86% peak)

¹¹ The firm rating of a substation is the maximum load the substation can carry under a single contingency condition (e.g., equipment failure at the substation). For more information on substation firm ratings please see Section 5.3.1 – Distribution Load Projects.

¹² Absent any additional investment to support the new load.

Exhibit 3.1.1.5 - Percent of Customers Served by Over-firm Substations in the High EV Adoption Scenario



These additional loads will worsen existing capacity constraints on the distribution system and will require investment, initially to address equipment overloads on grid edge equipment, and with time, to also mitigate impact on the upstream grid equipment, including substations. Substations with limited available capacity will reach or exceed their firm rating, increasing the risk of outages during contingency conditions. For example, an equipment failure may occur at the substation or upstream on the subtransmission system.¹³ Increased loading on substations and circuits will restrict the flexibility and resiliency of the grid, as load will not be able to transfer between locations for planned or unplanned work. As electrification-driven load growth continues, existing grid capacity constraints will increase, posing risks of accelerated equipment aging and failures. The impacts of electrification on grid edge assets, expected to occur even under lower levels of electrification, will drive the need for proactive upgrades before widespread equipment overloads and failures can occur. Grid edge equipment upgrades may include replacing service lines, replacing smaller distribution transformer sizes (e.g., 15 or 25 kVA) with a larger size and adding transformers to allow for fewer customers with higher loads per transformer.

¹³ DTEE's subtransmission system serves as the vital grid link between the ITC transmission system and the DTEE distribution system. Please see Section 9.2 Subtransmission Redesign and Rebuild Program for more details.

The Company will continue to monitor signposts around electric vehicle growth, charging availability and government legislation. These include the historical rate and magnitude of EV adoption within its service territory, the growth of public EV chargers and EV fleets, and favorable government public policy that supports customer EV adoption. Since the 2021 DGP, the Company has continued to evaluate the status of these signposts and has monitored major developments, such as the ongoing execution of the MI Healthy Climate Plan¹⁴ and the passage of the Infrastructure Investment and Jobs Act (IIJA)¹⁵ and Inflation Reduction Act (IRA).¹⁶

3.1.2 Increasing Catastrophic Storm Scenario

Climate change is driving an increase in the frequency and severity of extreme weather events across the upper Midwest (Minnesota, Wisconsin, Michigan), a trend recognized by several organizations conducting weather assessments of the region (see Exhibit 3.1.2.1 below). Additionally, the Great Lakes Integrated Sciences & Assessments (GLISA) reports that occurrences of severe storms have increased in the Great Lakes region



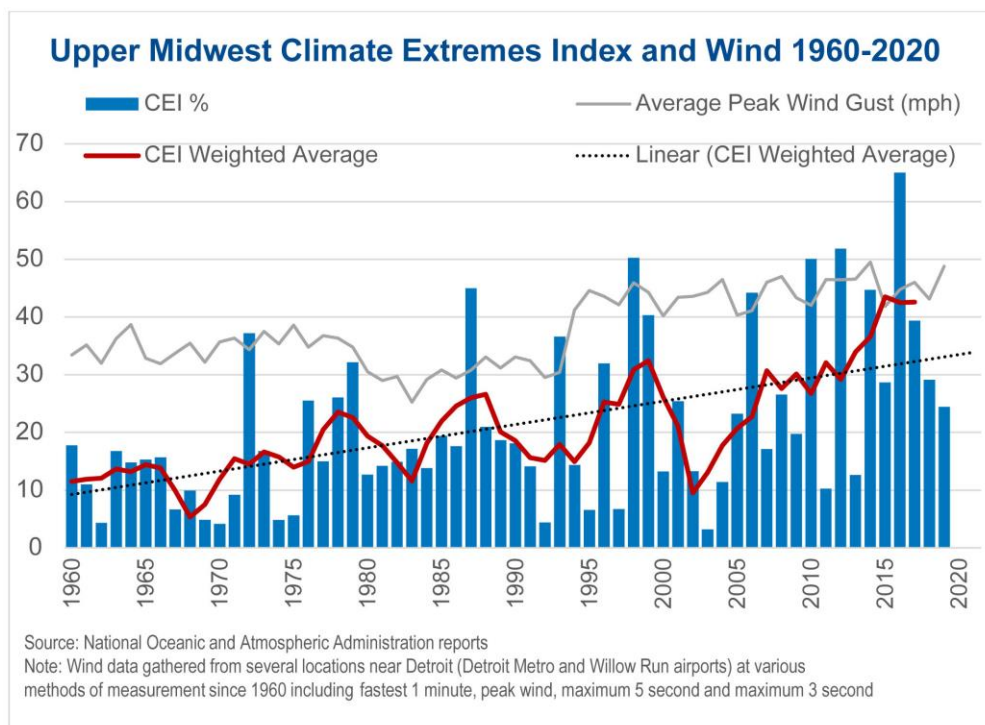
specifically, and this trend is likely to continue as climate change progresses¹⁷. DTE's increasing catastrophic (CAT) storms scenario analyzes the risk to the Company's infrastructure stemming from these weather shifts. The storm scenarios define thresholds for storms to be considered catastrophic, then differentiates those events into two categories: CAT-1 level storms, affecting 5% of the customer base and CAT-2 level storms, affecting 10% or more of the customer base.

¹⁴ [MI Healthy Climate Plan \(michigan.gov\)](https://michigan.gov/healthyclimate)

¹⁵ [The Bipartisan Infrastructure Law Will Deliver for Michigan | US Department of Transportation](https://www.transportation.gov/bipartisan-infrastructure-law)

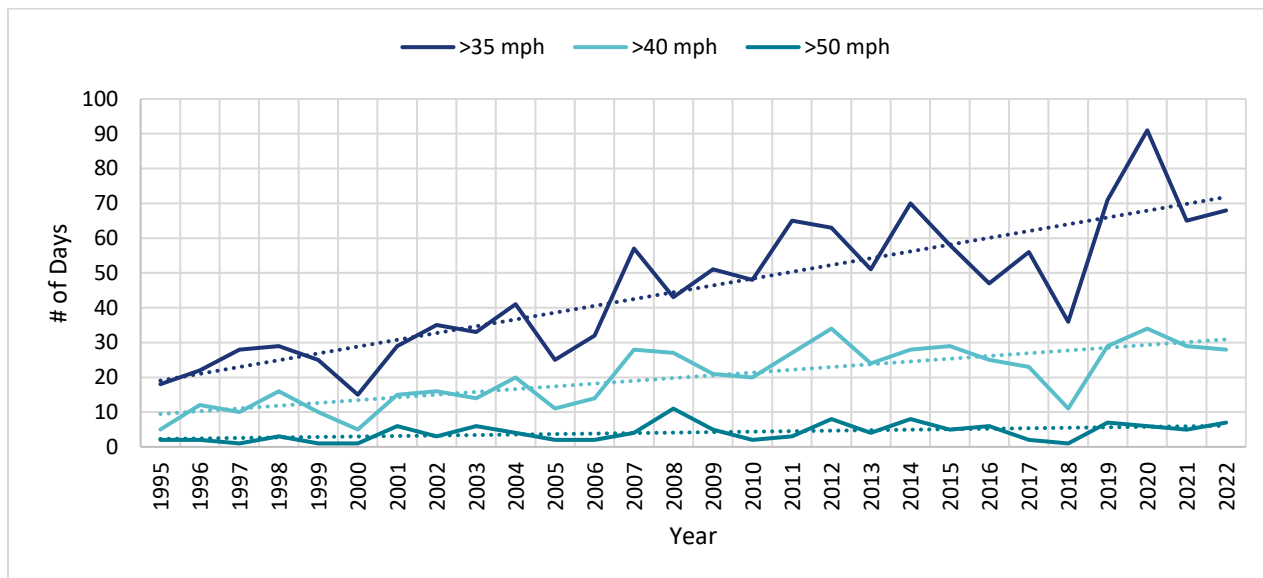
¹⁶ [¹⁷ \[Climate Change in the Great Lakes Region References | GLISA \\(umich.edu\\)\]\(https://umich.edu/glisa/references\)](https://www.whitehouse.gov/fact-sheets/2022/08/FACT-SHEET-One-Year-In-President-Biden-s-Inflation-Reduction-Act-is-Driving-Historic-Climate-Action-and-Investing-in-America-to>Create Good Paying Jobs and Reduce Costs | The White House</p></div><div data-bbox=)

Exhibit 3.1.2.1 - Upper Midwest Extreme Weather is Increasing in Frequency and Intensity



In Michigan, the 2019 Michigan Hazard Mitigation Plan (MHMP) identified severe winds and ice storms as high-frequency hazards for the regions of Michigan encompassing the DTEE service area. The MHMP further reported an average of 395 annual extreme wind events across Michigan with a future upward risk trend. Within DTEE’s service territory, this has been supported by observations on wind gust data from Detroit Metropolitan Airport, shown in Exhibit 3.1.2.2 below.

Exhibit 3.1.2.2 - Detroit Metropolitan Airport Wind Gust Data

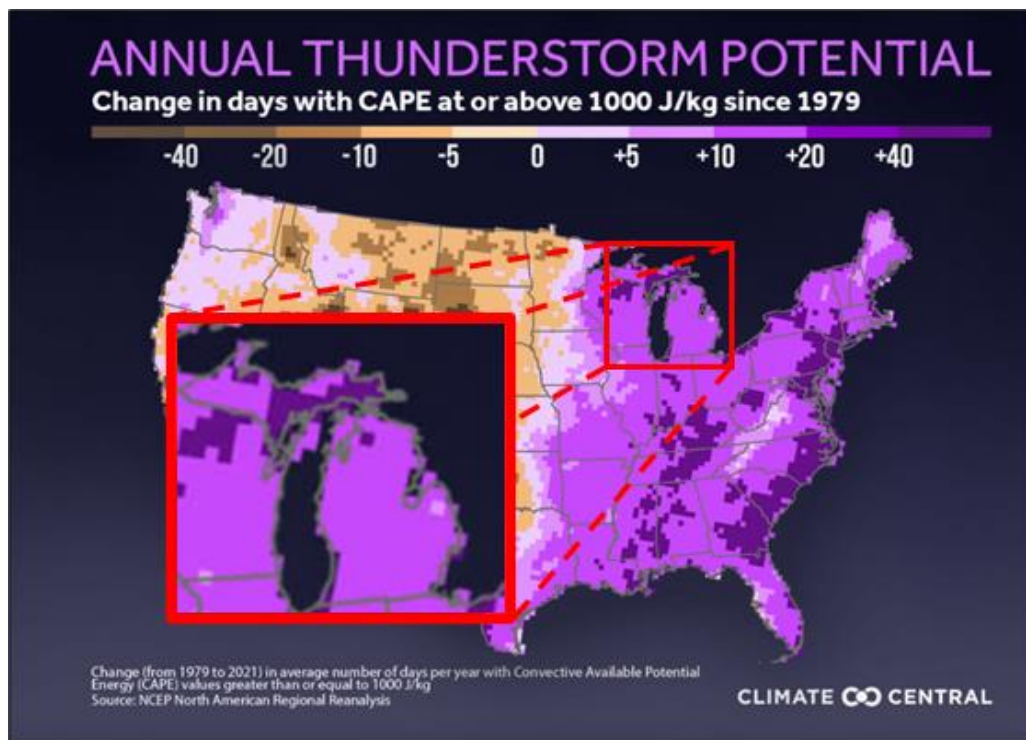


Another indicator of increasing extreme weather in Michigan is the annual increase in the number of days with higher Convective Available Potential Energy (CAPE), which can be thought of as the amount of energy available for a developing thunderstorm,¹⁸ with higher values translating to greater potential for severe storms.¹⁹ In Michigan, higher CAPE days have become more frequent, as shown below in Exhibit 3.1.2.3.

¹⁸ [What is Cape? - National Weather Service](#)

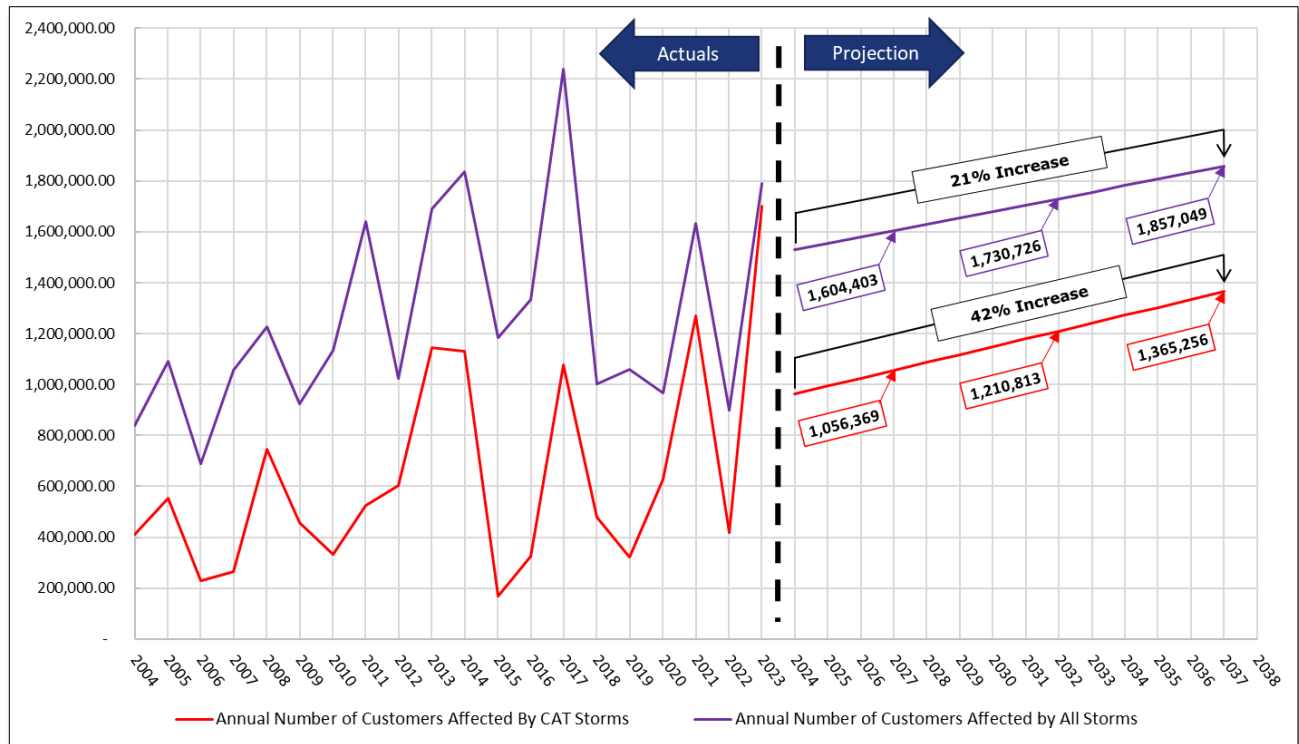
¹⁹ [Changing Thunderstorm Potential | Climate Central](#)

Exhibit 3.1.2.3 – Higher CAPE Days Have Become More Common in Michigan



There are large uncertainties when projecting extreme weather events due to limitations in existing weather models and inaccurate or missing historical data. Despite this, the trends indicate DTEE's service territory will likely be facing more extreme weather patterns in the future. For the increasing catastrophic storms scenario, the team's plausible forecast was a future where severe weather events increase in intensity. Absent any upgrades to the system, the forecast assumes that the number of customers affected by catastrophic storms will increase, as shown below in Exhibit 3.1.2.4. While the main driver of this forecast is assumed to be the increasing intensity of severe weather, another factor is DTEE's aging and increasingly beyond end-of-life equipment, which is less able to withstand the impacts of severe weather.

Exhibit 3.1.2.4 – The Number of Customers Affected by CAT Storms Is Increasing Each Year



Because of the distribution system’s aging equipment, configuration and existing capacity constraints, DTEE’s grid is increasingly vulnerable to the impact of extreme weather. Storms can cause widespread outages that disrupt service to customers for extended periods of time, as well as damage equipment, resulting in costly repairs. Compounding forms of extreme weather can exacerbate the negative effects of storms on DTEE’s grid infrastructure. For example, periods of high heat can stress the grid, overloading equipment and limiting the ability to transfer customer load to other circuits during outages. As another example, heavy precipitation events can cause flooding, impacting underground equipment and saturating the soil, making trees more likely to uproot and fall into power lines during periods of high winds.

Exhibit 3.1.2.5 - Tree Damage to DTEE Equipment in the Webberville Community (July 26,2023)



In response to the impacts of extreme weather, DTEE will strengthen the distribution grid to enhance system reliability and resiliency. Grid strengthening includes replacing aging overhead equipment with stronger poles, fiberglass crossarms and polymer insulators, as well as developing options such as undergrounding overhead wires.

Signposts that DTEE will continue to monitor in the catastrophic storm scenario include increasing storm severity and frequency; communities implementing resiliency initiatives and projects, including the construction of resilience hubs or community centers that support residents when extreme weather events occur; weather patterns and environmental conditions that increase the likelihood of wildfires; and government policy and initiatives to support resiliency infrastructure projects.

3.1.3 Distributed Generation/Distributed Storage Growth Scenario

The Distributed Generation/Distributed Storage (DG/DS) scenario focuses on the adoption of distributed generation and storage technologies that can reduce customer electricity demand and, in some cases, export power back to the grid. Both DG and DS are classified as subsets of distributed energy resource (DER) technologies by the MPSC,²⁰ which defines DER as, “source of electric power

²⁰ MPSC Case U – 20147, August 20th Order, Pg. 11.

and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.”

While there is more than one type of DG, customer owned solar photovoltaic (PV) is the most common today. Since 2007, through legacy net metering programs and the more recent distributed generation program,²¹ the Company has supported customers in the interconnection of their DER projects. Recently, DTEE increased its DG cap from 1% to 6% of its average in-state peak load for the preceding five calendar years. Technological advances and public policy (e.g., tax credits) have reduced DER costs and payback period, which is expected to drive increased customer adoption. Another force of DER growth is expected to come with the Midcontinent Independent System Operator’s (MISO) ongoing implementation of FERC Orders 841 and 2222, which when implemented can provide residential as well as commercial and industrial (C&I) customers an opportunity to participate in the wholesale market. In addition, federal and state grants are expected to provide additional funding for residential and community solar projects.



The Company’s 2022 IRP examined multiple DG adoption forecasts, including the “aggressive customer-owned distributed generation” sensitivity,²² analyzing it for distribution planning purposes as the plausible forecast for residential and small C&I solar PV growth. Along with this forecast, it is expected that ~55%²³ of PV residential solar installations will include a battery energy storage system, potentially resulting in an additional 144 MW of added residential storage capacity through 2037. The plausible forecast is summarized in Exhibit 3.1.3.1 below.

²¹ [About DTE's Distributed Generation Program](#)

²² This stakeholder- requested IRP forecast scenario utilized an aggressive assumption for solar photovoltaic adoption, combined with solar system capital costs that were set to align with NREL’s 2021 annual technology baseline aggressive scenario. See: <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000004qW9sAAE>

²³ From internal DTEE interconnection data. The 55% attachment rate used in the DG/DS scenario matches the highest annual attachment rate observed in the previous three years of DER interconnection data (2020-2022).

Exhibit 3.1.3.1 - DG/DS Scenario Capacity Forecast (2027 – 2037)

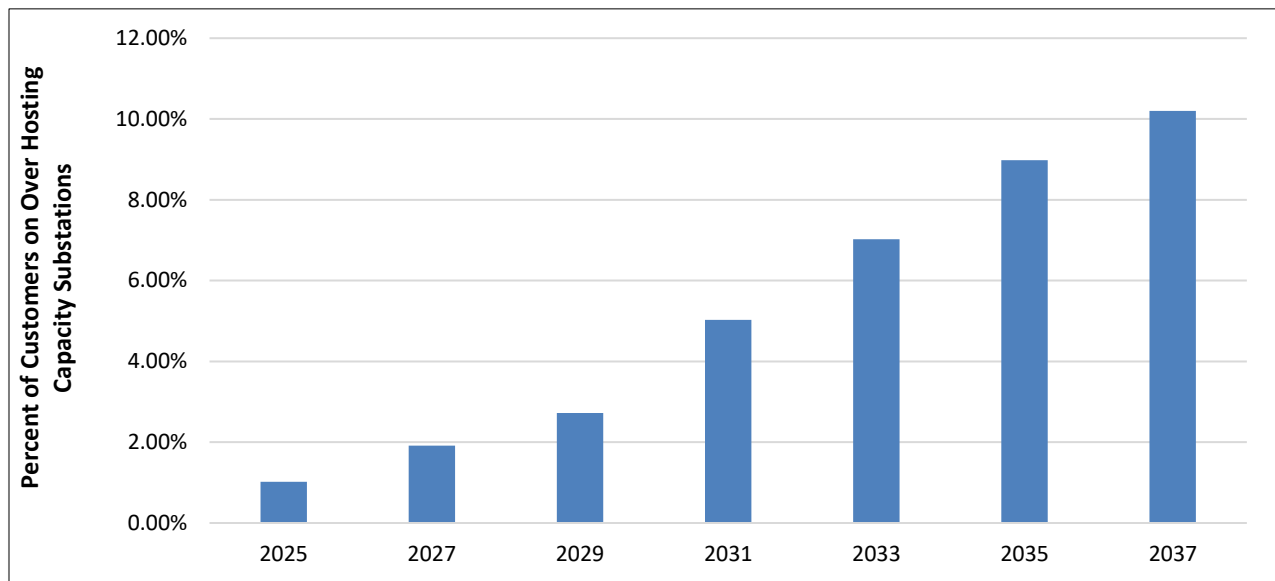
Key Drivers	2027	2032	2037
Solar PV – Residential	107 MW (0.97% peak)	226 MW (2.0% peak)	355 MW (3.1% peak)
Solar PV – Small C&I	74 MW (0.66% peak)	153 MW (1.38% peak)	236 MW (2.0% peak)
Storage – Residential	35.7 MW (0.32% peak)	87.6 MW (0.79% peak)	144 MW (1.26% peak)
Storage – Small C&I	2.6 MW (0.02% peak)	6.5 MW (0.06% peak)	10.5 MW (0.09% peak)

The introduction of DER into the distribution grid may provide an opportunity to gain a variety of distribution grid benefits, such as reduction in distribution system losses, mitigation of overloads and adding ancillary services that improve power quality and voltage regulation. However, since adoption levels are still relatively low in Michigan, quantification of these benefits is not fully understood today. In addition to grid benefits, moderate to high levels of DER can also cause localized grid challenges, including voltage and thermal issues impacting power quality in addition to protective device malfunctions. As customer adoption increases, the Company will continue to study the grid impacts of DER to understand both the benefits and challenges for the distribution system.

The Company will invest in grid communications and controls to support the DER operating benefits, while maintaining the stability and quality of power delivered to all customers. This may include a need to curtail generation at those sites during certain conditions, as well as making other investments in system upgrades. The number of customers on substations where the desired level of installed solar capacity exceeds a substation's hosting capacity²⁴ limit will likely increase in the future if upgrades are not made to distribution system equipment implemented through the interconnection process (shown below in Exhibit 3.1.3.2).

²⁴ Hosting capacity is defined as the amount of DER that can be accommodated on a circuit or substation without adversely impacting operational criteria, such as power quality, reliability and safety, under existing grid control and operations and without requiring infrastructure upgrades.

Exhibit 3.1.3.2 - Percentage of Customers on Substations where Installed Solar Capacity Exceeds the Hosting Capacity Limit (2025 – 2037)



The signposts the Company will continue to monitor are those affecting customer adoption, incentives and market participation. These include MISO's ongoing implementation of FERC Order No. 2222, growth of solar and storage installations in the Company's service territory, and any public policies related to DG and storage. Of these indicators being monitored, compliance with MISO's requirements for FERC Order No. 2222 is of special note, as the associated grid implications will be a core driver for a number of technology and automation investments. This includes the Distributed Energy Resource Management System (DERMS) program, interconnection process enhancements, and planning tool upgrades (see Section 10.2 – Operational Technology Roadmap – and Appendix C.2 – Grid Management Investments, DERMS & FERC2222 for more details).

3.1.4 Scenario Impacts

As these scenarios highlight, the future grid will require greater flexibility to quickly respond to changes in load demands, generation and system configurations on the distribution system. The grid will also need to be more robust to withstand more extreme weather predicted in the future. Infrastructure upgrades - such as conversion - will aid the system in accommodating customer DG/DS adoption and demand growth from electrification. Lastly, more technology will be needed to allow for grid monitoring and control technologies (e.g., ADMS) that can be used by grid operators to ensure

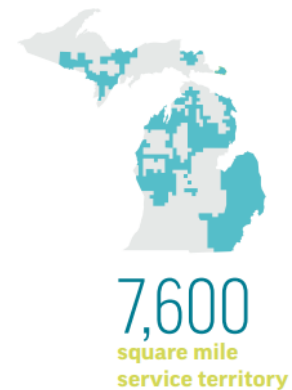
system reliability and maintain the quality of power delivered to customers. The current state of the Company's grid will be discussed next in Section 4. Section 5 will revisit the impacts of scenarios in determining the gaps that need to be addressed to improve the system.

4 State of the Grid



4.1 Current Electric System Overview

DTEE's distribution grid includes approximately 31,000 miles of overhead distribution lines and 14,500 miles of underground distribution lines. Its service territory encompasses 7,600 square miles and includes approximately 2.3 million residential, commercial and industrial customers. DTEE's electrical grid consists of six voltage levels: 120kV, 40kV, 24kV, 13.2kV, 8.3kV and 4.8kV. Maps depicting the distribution and subtransmission voltages across the service territory can be found in Exhibit A.1. in Appendix A.



As many of DTEE's distribution assets have been in operation for several decades, a significant portion of the distribution system's equipment is reaching, or has exceeded, the typical industry lifespan, resulting in a higher occurrence of outage events when compared to peer utilities. Older equipment may have deteriorated due to long exposure to the elements, but in many cases this equipment was also built to less resilient standards of the past. Certain areas of the distribution system are in locations difficult to access such as backyards or wooded areas. Distribution lines in abandoned alleyways are particularly challenging to access, causing delays in restoration efforts and complicating equipment maintenance. Additionally, the electric system faces limitations on capacity in some areas, which at times present difficulties in accommodating new customer loads. The Company has seen a growing number of outages, particularly during extreme weather. Redesign and modernization will improve reliability and help to meet the evolving demands of today's energy landscape.

4.1.1 Subtransmission System Voltages

DTEE's subtransmission system consists of three voltages: 24kV, 40kV and a limited amount of 120kV, which supplies customer-dedicated substations. The subtransmission system steps down the transmission voltage for delivery to distribution and industrial substations. The 24kV segments of the system were built to serve the 4.8kV sections of DTEE's distribution system but do not align with modern standards; however, the newer 40kV lines are being constructed to meet industry standards. Similar to distribution equipment, much of the subtransmission equipment is approaching or is beyond typical industry lifespans. Maintenance access to sections of the overhead subtransmission lines is regularly impeded by obstacles such as wooded areas and railroads, often delaying restoration after a failure. Load constraints on the subtransmission system limit operational flexibility, creating delays to shutdowns needed for equipment maintenance and for prepping the system to accommodate new loads. These factors could lead to increased failures, resulting in the loss of redundancy, or in some cases to large, sustained outages. Section 9.2 further discusses the current state of the subtransmission system, including challenges and limitations as well as the strategies and investments to mitigate these issues.



4.1.2 Distribution System Voltages

DTEE's initial distribution system voltage was 4.8kV, which remains in active use today. The system was designed as an ungrounded delta configuration and banked secondary standard. Ungrounded delta configuration means that in order for a trip device to operate on the system, two of the high-power lines need to touch each other to create a fault the devices can see, in contrast to higher voltage grounded systems. In a banked secondary configuration, multiple transformers are interconnected to provide power to a small area of customers. This system has its strengths in resiliency, however, due to its ungrounded design, fault locating can be challenging and may complicate restoration efforts. Delta configuration is a design from the early 1900s. In most neighborhoods, the 4.8kV system was constructed as overhead rear-lot poles and wires, which was aesthetically preferable to front-lot construction. Right-of-way truck access was initially readily available through municipally maintained alleys in many areas, including much of Detroit. In the mid-1900s, many municipalities began to abandon alleys and allowed property owners to extend their

fence lines, preventing DTEE trucks from accessing the poles and wires. Consequently, the limited access significantly increased the time to locate and repair trouble on the 4.8kV system and increased the time required to perform tree trimming and maintenance work.

In the 1960s, DTEE began installing a 13.2kV distribution voltage. The 13.2kV system is a newer, grounded system with increased reliability. Because the system is a grounded configuration, the 13.2kV system can more easily accommodate automation technology when compared to the 4.8kV system. Additionally, the 13.2kV system is typically constructed to provide better access to locate and repair trouble.²⁵ These key



differences between the two systems mean average restoration time for an outage on the 4.8kV system is 70% longer than on the 13.2kV system. Other key reliability and operability advantages of the 13.2kV compared to the 4.8kV system are summarized below:

- The 4.8kV system has smaller conductors (wires), which are weaker in strength compared to those the on 13.2kV system
- Due to the voltage, a 4.8kV circuit has lower capacity and can only accommodate ~40% of the customers serviced by a 13.2kV circuit
- The 4.8kV system can have more significant voltage drops than the 13.2kV system due to higher impedance, making the 4.8kV circuits more susceptible to dropping below acceptable voltage limits
- Unlike the 13.2kV system, the 4.8kV system is an ungrounded delta configuration, making detection, location and protection of single-phase downed wires challenging

4.2 Reliability

DTEE customers expect and deserve reliable service. To better serve customer needs, DTEE has made reliability one of the core planning objectives. Measuring reliability performance helps drive operational performance improvement, prioritizes strategic investments and validates that those investments are delivering the intended benefits.

²⁵ The 13.2kV system is usually built along roadways which allows for easy access from bucket trucks.

4.2.1 SAIFI, SAIDI, and CAIDI

DTEE measures overall system reliability using the indices System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index and Customer Average Interruption Duration Index (CAIDI).

These three metrics are reliability performance indicators defined in IEEE Standard 1366 and summarized in Exhibit A.2 in Appendix A. These indices are typically calculated in two ways: 1) All-Weather conditions, and 2)



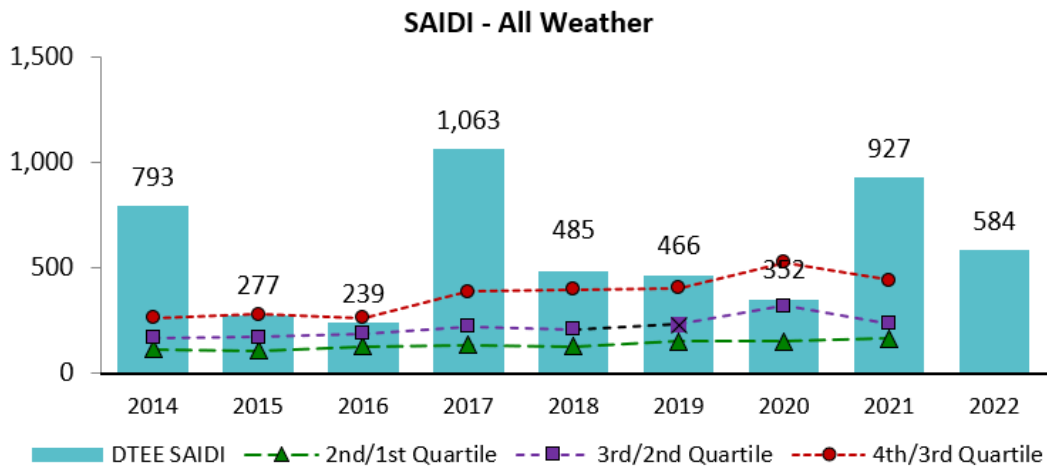
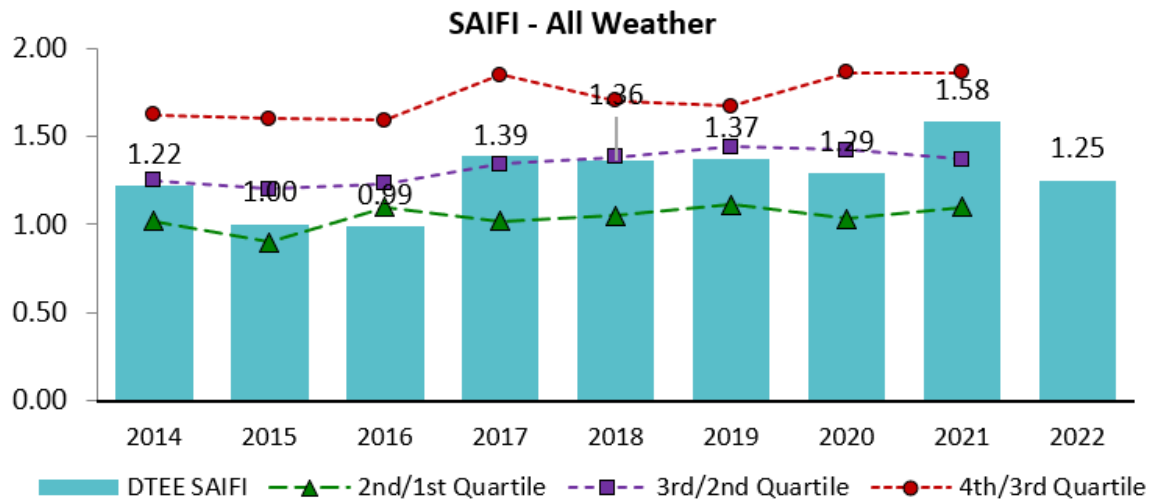
excluding Major Event Days (MEDs). An MED is any 24-hour period in which there is a significant statistical difference in daily SAIDI; the calculation details are in IEEE Standard 1366.²⁶ Excluding MEDs gives a clearer picture of day-to-day system performance and customer experience absent significant weather events, which are highly variable from year to year.

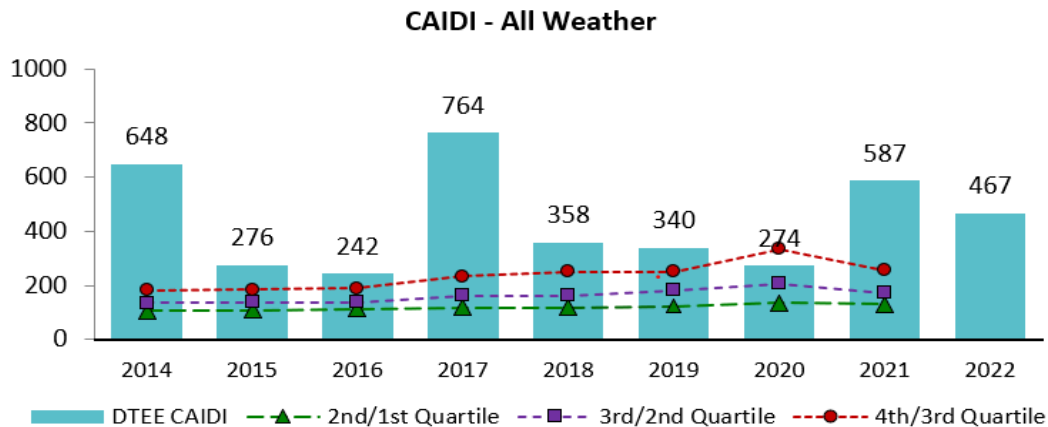
In addition to the IEEE standard indices, DTEE also tracks reliability performance under various weather-related conditions: catastrophic storms, non-catastrophic storms and excluding storms. Analyzing these stratifications allows better insight into reliability performance, root causes of customer outages and the remediations needed to improve performance under different conditions. Reliability data in these various weather conditions can be seen in Exhibits A.3 - A.6 in Appendix A.

Exhibit 4.2.1.1 below shows reliability statistics over the last nine years for All-Weather indices. Over this span, DTEE has consistently been in the second and third quartile for SAIFI, and primarily in the fourth quartile for SAIDI and CAIDI.

²⁶ [Microsoft PowerPoint - Without video IEEE 1366- Reliability Indices 2-2019.pptx](#)

Exhibit 4.2.1.1 Reliability Statistics - All Weather





4.2.2 Causes of Interruptions

The Company analyses what causes interruptions to DTEE's electric distribution system to address primary outage drivers and improve reliability. Exhibits 4.2.2.1 through 4.2.2.3 found below illustrate the percentage contribution to customer minutes of interruption, customer interruptions and outage events by cause. Tree/wind interference is the leading cause of DTEE's customer minutes of interruption (SAIDI) and number of customer interruptions (SAIFI). Tree/wind is also the leading cause of outage events (within DTEE's Outage Management System) on the DTEE system. Equipment failures are the second leading cause of the SAIFI outage events on the DTEE system.

Exhibit 4.2.2.1 5-Year Average Customer Minutes of Interruption by Cause (SAIDI)

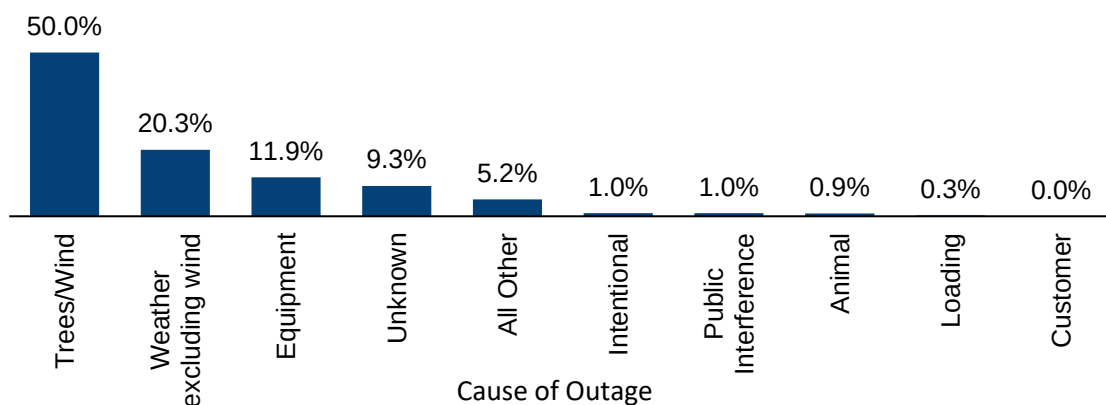


Exhibit 4.2.2.2 5-Year Average Customer Interruptions by Cause (SAIFI)

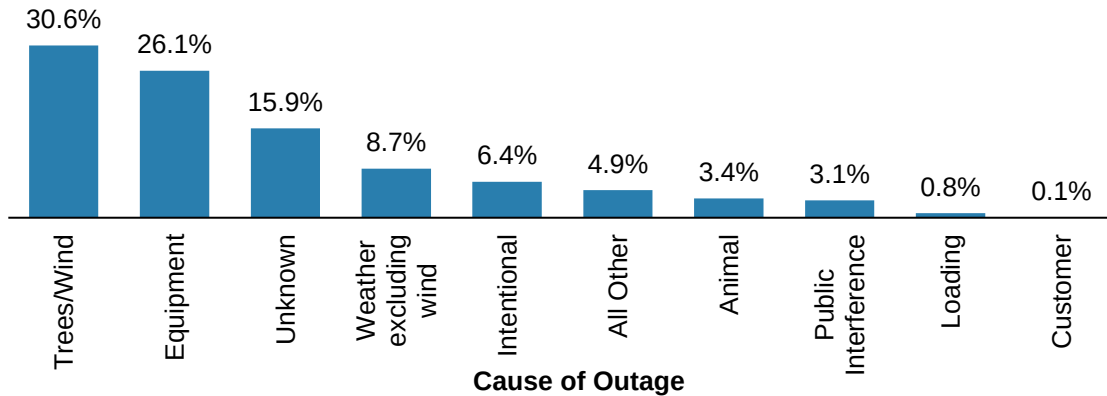
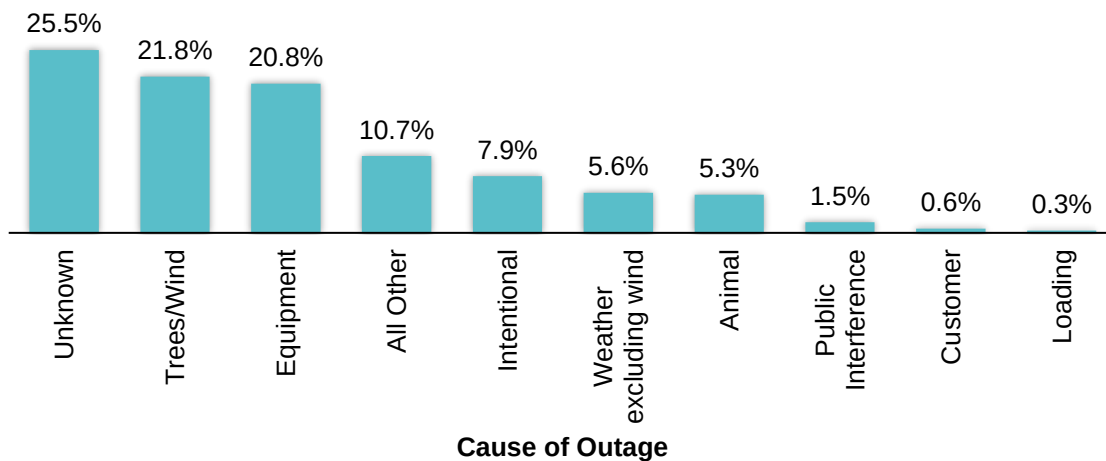


Exhibit 4.2.2.3 Five-Year Average Outage Events by Cause



Note: Equipment includes substation, underground and overhead equipment, and hardware

4.3 Distribution System Assets

4.3.1 Distribution System Asset Overview

There are 18 assets that have the greatest potential impact on customer reliability. The average age, range of ages and life expectancy for the 18 asset classes are summarized in Exhibit 4.3.1.1. The life expectancy is based on manufacturer recommendations, industry benchmarks, EPRI (Electric Power Research Institute) Industry Database, NEETRAC (National Electric Energy Testing, Research & Applications Center) Asset Survival Plots and DTEE's data. Age can become a significant factor when

replacement parts become unavailable or, in specific cases, where asset health deteriorates sharply with age. However, DTEE also uses annual health assessments to evaluate its assets. The criteria for each asset were described in detail in Section 8 of the 2021 DGP and the risk factors have not changed since then. Sections 4.4.2-4.4.8 provide a detailed description for eight key asset classes. Additional detailed descriptions can be found in the 2021 DGP on pages 148-203.

Exhibit 4.3.1.1 Asset Age Summary

Asset (Section)	DTE Electric Age Range (Years)	DTE Electric Average Age (Years)	Life Expectancy (Years)	% of Asset Class at or Beyond End of Life
Substation Power Transformers (4.4.3)	0-99	43	40-45	49%
Network Bank Transformers	0 – 85+	46	20 - 30	91%
Circuit Breakers (4.4.4)	0 – 90	41	30 – 40	60%
Circuit Switchers	0 – 36	19	NA	NA
Relays	0-60+	33	15-50	NA
Switchgear	0 – 70	40	40	55%
Poles (4.4.5)	0-90+	46	40-50	50% ²⁷
Three-phase Reclosers (4.4.6)	0-34	10	20	10%
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	0-31	15	20	38.5%

²⁷ This number was calculated using 50 years as the number for expected end of life of poles.

40 kV Automatic Pole Top Switches	0-50+	21	40	35%
Overhead Capacitors	Oldest: 25+	NA	20	NA
Overhead Regulators	Oldest: 25+	NA	20	NA
System Cable (4.4.7)	0 – 100+	49	20 – 40	64%
Underground Residential Distribution (URD) Cable (4.4.8)	0 – 60+	26	40	23.6%
Manholes	1-100+	78	Varies based on construction and field conditions	NA
Advanced Metering Infrastructure (AMI meters)	0-13	6.5	20	0%

4.3.2 Substation Power Transformers

DTEE has approximately 1,600 substation power transformers connecting the transmission system (120kV) to the subtransmission system (40kV and 24kV) and to the distribution system (4.8kV, 8.3kV, and 13.2kV). The average age of substation power transformers is approximately 43 years. The Company has averaged over 15 power transformer failures per year over the past five years, including units that were identified²⁸ and proactively replaced before failure. Bushings, load tap changers and winding insulation breakdown account for approximately 65% of the failures. The



²⁸ Based on results from routine inspection and Dissolved Gas Analysis (DGA).

average age of transformers at the time of failure is approximately 48 years. Failures of substation power transformers can cause outages on multiple circuits simultaneously. Substation power transformer failures can also reduce system redundancy effectively increasing outage risk to customers for extended periods, sometimes impacting thousands of customers. Approximately 49% of substation power transformers are at or beyond expected useful life.

4.3.3 Circuit Breakers

A circuit breaker is an electrical switch that isolates faults on substation equipment, buses and circuits. Its basic function is to interrupt current flow after a fault is detected to minimize equipment damage due to high fault currents and to isolate the faulted asset from the electrical system. DTEE has approximately 6,000 breakers on the electrical distribution and subtransmission systems. This number is a mixture of oil, air magnetic, gas and vacuum breakers. Currently, 60% of all breakers are beyond expected useful life and 53% are candidates for replacement based on the findings in the asset health assessment. Included in this 53% are approximately 2,090 oil-filled breakers that require replacement due to a combination of multiple risk factors associated with that equipment, such as the environmental concerns of possible leaks. A failure of a circuit breaker can cause outages on multiple circuits and reduce system redundancy for an extended period during repairs. Depending on the extent of the failure and possible adjacent collateral damage, thousands of customers could be impacted for an extended duration. More information on breaker replacements can be found in Section 8.3.3.

4.3.4 Poles and Pole Top Equipment

DTEE owns more than one million distribution and subtransmission poles. In addition, DTEE has assets attached to nearly 200,000 poles owned by other utilities (e.g., Comcast, AT&T). The average pole age in the DTEE system is approximately 46 years. The useful life expectancy of a pole is 40 years for wood pine poles and 50 years for wood cedar poles, though the actual useful life can vary based on field conditions. Currently, 50% of poles in DTEE's system are at or beyond end-of-life.



Poles can fail for a variety of reasons, including vehicle strikes, damage from trees and branches and icing or wind loads above the design standard. As poles age they weaken and become more susceptible to failure.

Pole top hardware can also fail as equipment ages. That hardware includes cutouts, slack span sleeves, blackburn hot taps, ground wires, arresters, cross-arm parts, transformer parts, insulators, primary line sag, guy wire components, spacer blocks, neutrals on secondary taps and secondary equipment.

4.3.5 Three-phase Reclosers

An overhead three-phase recloser is a sectionalizing device that is installed at key points on overhead circuits. It acts like a circuit breaker by opening if high current is detected due to a downstream fault, such as a tree branch across two phases. Reclosers localize the fault to the circuit section beyond the recloser (downstream of the recloser), leaving customers intact on the remainder of the circuit (upstream of the recloser). Unlike a fuse that



will open and stay open, a recloser is designed to automatically attempt to reclose several times to restore the downstream customers if the fault has cleared. The open and reclose cycle allows a temporary fault, such as a small falling tree limb, to clear from the circuit and restore power to customers with only a momentary interruption. In the case of a sustained fault, the recloser will remain open and isolate the fault from the rest of the circuit. Reclosers can also be used to join two circuits together and can be programmed to automatically back feed parts of a circuit in the event of a power outage. Modern, three-phase reclosers offer remote functionality that can be utilized as part of a loop scheme. At a circuit level, loop schemes facilitate automation by transferring power into adjacent sections of the circuits when an outage is detected. Loop schemes are currently installed on approximately 5.5% of distribution circuits. Loop schemes are standard for all new or converted circuits. Efforts are currently underway to automate specific aspects of the 4.8 kV system where possible, and these efforts are discussed in section 10.1.

DTEE has a preventive maintenance program for overhead three-phase reclosers. Reclosers failing preventative maintenance inspection or failing in service are replaced or repaired. The average age

of the three-phase reclosers is 10 years, and approximately 10% of three-phase reclosers are at or beyond expected useful life.

4.3.6 System Cable

DTEE's distribution and subtransmission system has over 3,000 miles of underground system cable. System cable is large diameter cable surrounded by insulation that is typically installed in conduit and requires manholes or switch cabinets approximately every 100 to 800 feet, depending on the cable type and path. Manholes and switch cabinets provide locations where sections of cable can be pulled through the conduit and spliced together. System cable provides higher storm resiliency than overhead lines; however, the cost and time to install, repair or replace is much greater. The increased time to repair/replace system cable makes it imperative that redundancies are maintained, such that when a cable fails, its load can be shifted to another power source (often another system cable) to avoid a long duration customer outage. System cable is especially useful to route multiple circuits through a small, congested area (e.g., entrances and exits of a substation).

Exhibit A.7 in Appendix A illustrates five of the six major types of underground system cable installed in DTEE's distribution system. Exhibit 4.3.6.1 below shows the types, quantities, average age and life expectancy of system cables in the DTEE system. The average life expectancy of system cables is 40 years or less, although actual useful life varies depending on cable type and field conditions. System cable is a critical component for both the subtransmission and distribution systems. A cable failure reduces system redundancy and resiliency and can interrupt many customers for an extended period. Of DTEE's system cable, 64% is at or beyond end-of-life and 28% has been assessed as high-risk of failure. Information on system cable replacements can be found in section 8.3.2.

Exhibit 4.3.6.1 Underground System Cable Ages and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Post 1990 (Tree retardant)	XLPE Pre 1990 (Non-tree retardant)	BUYTL
Miles	2,219	707	114	49	50	59	7
% of Total Population	69%	22%	4%	2%	2%	2%	0%

Average age	52	15	61	55	20	37	53
Life Expectancy	40	35	40	40	40	25	20

4.3.7 Underground Residential Distribution (URD) Cable

Underground Residential Distribution (URD) is a specific type of cable designed and used in underground residential applications on the Company's secondary electric system. URD consists of small-diameter cable surrounded by polyethylene insulation, which is either directly buried or installed inside conduit into the ground. Since URD is buried underground, it is not exposed to above ground tree-related or other overhead-related outages. However, it is more expensive to install and repair than overhead lines. Underground cable failures are less frequent but take a long time to repair or replace. DTEE is currently evaluating options to underground portions of circuits to improve reliability for customers. The average age of DTEE URD cable is 26 years. DTEE currently has 2,682 miles of URD cable, or 23.6%, that is ready for replacement. Information on underground residential distribution (URD) cable replacement can be found in Section 8.3.2.



4.3.8 Small Wire

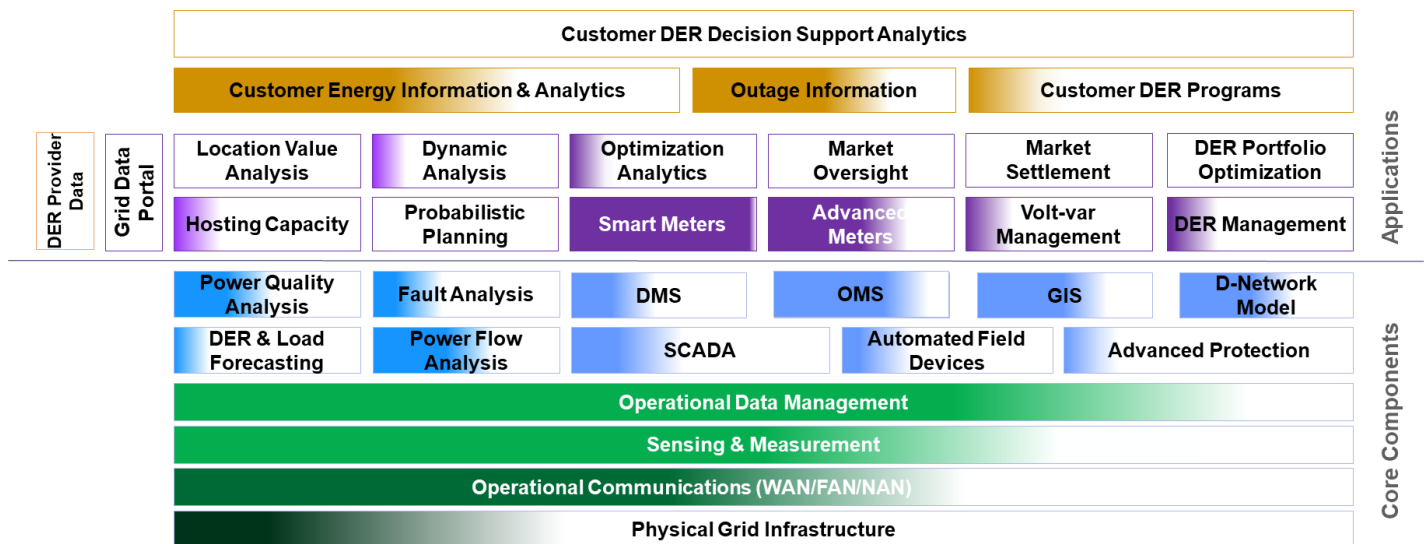
Small wire is identified by the wire gauges #8, #6 and #4. These wire sizes are no longer used for new installations. Small wire is of concern due to its weaker mechanical strength, causing it to break more easily when tree branches fall on it. To improve reliability, new wire specifications provide strengths that are two- to three-times stronger than small wire sizes. There is no standalone proactive replacement program for small wire. However, small wire replacement is performed during other capital work to support load growth, conversion and consolidation, or reliability improvements.

5 Gaps to Future State



After reviewing the scenario analysis discussed in Section 3, and assessing current state infrastructure in Section 4, the Company leveraged the United States Department of Energy Distribution System Platform Initiative (DSPx) framework to help determine where gaps exist between the grid in place today and the future grid needed to serve customers. The DSPx framework segments planning and operational technologies in order to clearly display the progress the Company has made in each area and those where investment is most needed. The figure below is adapted from Volume 3 of the DSPx framework and has been included to conceptually show the status of DTEE's core grid modernization platform and application layers. The more color a bar has, the more advanced DTEE is in that area; large amounts of white space indicate a gap that needs to be closed.

Exhibit 5.0.1: DTEE Grid Modernization Status



Reference U.S. Department of Energy Modern Distribution Grid Project Volume 3 Figure 8: <https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx>

Using the DSPx framework in conjunction with the scenario analysis discussed in Section 3, further highlights current state gaps as well as potential future system gaps. As investments are weighed against each other, an indicator of the most valuable investments is the ability to address grid needs for multiple scenarios. For example, a physical grid infrastructure investment in voltage conversion will create capacity required in the electrification scenario, increase resilience by modernizing and hardening equipment benefiting the CAT storm scenario and increase hosting capacity necessary to support the DG/DS scenario.

For simplicity, DTEE has summarized the gaps to future state that were derived from this analysis into four categories:

- 1) Physical Grid Infrastructure
- 2) Observability and Controls
- 3) Analytics and Computing Platforms
- 4) Communications

5.1 Physical Grid Infrastructure

Physical grid infrastructure is by far the largest investment gap identified (by size of investment required) and is foundational to meeting all future grid needs. Much of the current infrastructure is old and failing in ever-increasing amounts, making the system particularly susceptible to extreme weather impacts. Capacity constraints at both the circuit and substation levels will restrict the ability to:



(1) add new customers and new load forecast from electrification, (2) accommodate the voltage fluctuations caused by DER, and (3) limit current and future ability to reroute power during outages. Based on DTEE's 2022 area load analysis, approximately one-third of distribution substations currently have loading constraints, either within the substation or on its circuits. These capacity concerns are particularly problematic on the 4.8kV system where the lower voltage is limiting.

Additionally, fault locating can be challenging on the 4.8 kV system and the limited ability to utilize circuit automation on the system can complicate restoration efforts. The 4.8kV infrastructure is also the oldest on the system. While not the only factor, aging equipment can increase the probability and severity of failure resulting in customer outages and the need for emergency equipment replacements and repair.

Solving this gap will not be easy or quick. It will take sustained investment in voltage conversion and infrastructure replacement programs including overhead, underground and substation equipment. Lastly, new capacity will need to be added to accommodate future load demands. Increased capacity will need to primarily come from conversion work and 13.2kV substation/circuit expansions, while a smaller part of the solution set will be load offsets from customer DER and/or energy conservation.

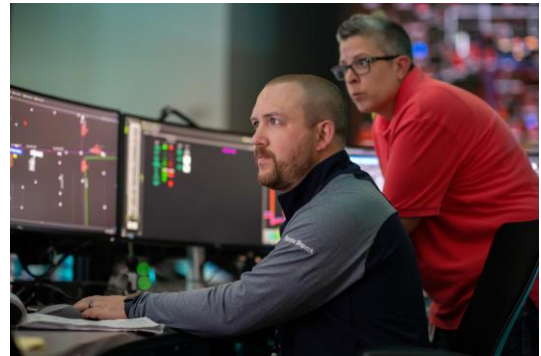
More information on Physical Grid infrastructure Investments can be found in Section 8 - Infrastructure Resilience and Hardening and Section 9 - Infrastructure Redesign and Modernization.

5.2 Observability and Controls

The Company's electric distribution grid requires increases to both remote observability and control of the assets operating on the system. Benefits of observability and control include:

- **Automating the Grid:** Automated technology to control switching devices to reconfigure the grid during outages, enabling remote restoration that will be particularly beneficial during extreme weather events
- **Understanding Problems:** The ability of system operators to understand in real time when and where outages occurred and what current system restoration options are available
- **Monitoring Distribution:** Monitoring of system attributes such as voltage, current and harmonics – information needed to maintain a stable electric grid while managing large volumes of DER and the impacts of electrification
- **Coordinating Resources:** Work with certain DER assets (e.g. DER aggregations, energy storage, utility owned solar facilities) to maintain system integrity and reliability

Increasing the number of DER on the Company's system creates a need for enhanced, granular monitoring and sensing capabilities because DER interacts with the grid in fundamentally different ways than most current generation assets. Consequently, the impact of DER on the grid will need to be managed carefully. Everyday grid operations such as power quality management will become more dynamic as customers adopt DER and transportation is electrified, resulting in a wider range of less predictable loading conditions.



Storms will further threaten grid reliability and increase outage volumes unless effective control schemes are able to both sectionalize the grid and transfer load to adjacent circuits.

Increasing control capabilities to adapt to these unique, and at times overlapping, impacts support DTE's safety and reliability priorities and will assist the Company in integrating more DER into its distribution system.

More information on Observability and Controls investments can be found in Sections 10.1 - Grid Automation and 10.2.1 -Grid Management Investments.

5.3 Analytics & Computing Platforms

Investments in observability and controls will provide the Company with increased volumes of associated data. It is important to have the capability to quickly and efficiently process this data while maintaining its quality. This is accomplished through investments in analytics and computing platforms that can ensure the quality and processing of large amounts of data to enable fast, informed decisions. DTEE has made significant progress in improving its analytics and computing platforms in recent years and recognizes that even more work will be required to keep pace with the increasing volumes of data available.



Accurate distribution system models and loading data will become increasingly important as planners work to forecast areas of DG/DS and EV adoption, as well as identifying distribution abnormalities well in advance of when they occur. Uncertainties surrounding consumer EV charging patterns will further complicate planning and forecasting efforts. The grid impacts associated with electrification, DER and increasing storms will require expanded data collection and an advanced analytics platform to assist the Company with complex decisions relating to planning and operating the grid.

For more information on analytics and computing platforms investments see Section 10.2.2 -10.2.5.

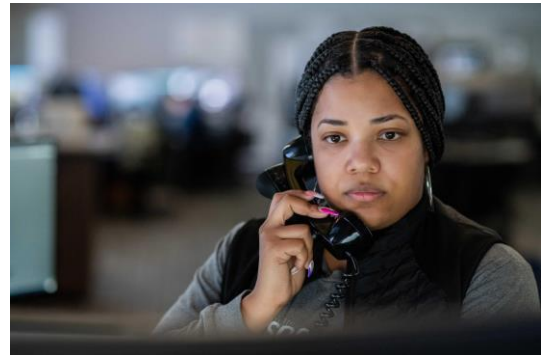
5.4 Communications

Communications technology is required to support the observability and control technology discussed in Section 5.2. This technology will enable data generated from smart grid devices to move between the equipment in the field and the ESOC. The current communications architecture must be enhanced to meet the throughput, latency and reliability standards that a modern grid requires.

Grid automation is needed to improve grid resiliency during extreme weather events; this automation requires communications infrastructure enhancements. Additionally, as DER and electrification growth occur, the number of connected devices and associated volumes of data that must be sent

securely and in near-real time will also increase. While the Company has made headway with its telecommunications investments to date, many of the older assets within the current telecommunications architecture are incompatible with modern systems and incapable of handling the data requirements necessary to support DER growth. The Company's radio-based communications system, for example, was not initially designed to support large volumes of data and many areas of DTEE's service territory lack high-bandwidth communications. The Company has also had to adapt to several external regulatory changes from the FCC. The FCC spectrum reallocation has negatively impacted utility communications on wireless point-to-point and point-to-multi-point systems, as has the phase out of 3G cellular networks, which is the basis for the current AMI architecture.

DTEE is also susceptible to network blackouts caused by using leased Internet Service Providers and leased Cellular Service Providers that do not build their networks with the same level of resilience that the electric grid requires. This has resulted in a strategic shift in recent years to build networks privately owned and maintained by DTEE to enable the Company to securely control and operate reliable telecommunication systems.



To close these communication infrastructure gaps, additional privately owned tiered telecommunications systems are needed, including deploying fiber with enough coverage to support critical sites such as data centers, service centers, power plants, substations and renewables sites. In addition to fiber deployments, wireless point-to-point and point-to-multi-point systems will be needed to supplement telecommunications needs to intelligent edge devices such as AMI meters. This tiered telecommunications system design will place emphasis on system redundancy and resiliency, allowing the Company to better operate during outages on the communications network as well as the electrical system.

For more information on communications investments see Section 10.1 - Grid Automation.

6 Distribution Investment Strategy



DTEE's investment strategy will transform the grid and deliver significant benefits to customers, including improved reliability, reduced system risk, increased capacity to serve current and future load and enhanced capabilities to integrate the technologies that customers are adopting. Overall, the Company plans to invest \$5.8 billion in strategic capital and almost \$600 million in tree trimming across the five-year period described in this plan. DTEE has organized these strategic investments in the grid into the following four pillars, which the Company has used since the filing of the 2018 distribution plan:

- Tree Trimming
- Infrastructure Resilience and Harding
- Infrastructure Redesign and Modernization
- Technology and Automation

Each of these four pillars is designed to address grid needs identified through the scenario planning process described in Sections 3 through 5. The projects that receive the highest score in the Company's Global Prioritization Model (GPM), and therefore are assessed as having the highest impact, are prioritized for investment.

6.1 DGP Investment Summary and Impact on Reliability

Rebuilding and modernizing the electric grid is identified as the most important investment need in Section 5. Several factors contributed to this determination. First, much of the current infrastructure is at or beyond expected useful life and susceptible to failure, particularly when exposed to extreme weather. Second, approximately one-third of the physical grid has some form of load constraint on the subtransmission, substation or circuit level. Third, parts of the grid, specifically the 4.8kV distribution system, were designed in a configuration that has resulted in both safety and technological challenges. Three of the four pillars focus on improving the physical grid:

- **Tree Trimming (Section 7)** – The Tree Trimming investment includes both an enhanced specification to improve the impact of trimming trees, and a surge to bring the entire system on-cycle to this enhanced specification. Bringing the system on-cycle and maintaining that cycle is critical to minimizing the impact trees have on the physical grid infrastructure, particularly during extreme weather.
- **Infrastructure Resilience & Hardening (Section 8)** – Projects and programs in this pillar are focused on replacing aging infrastructure to improve grid reliability and resilience in the short term. This pillar addresses the overhead system through programs such as Pole Top Maintenance and Modernization and 4.8kV Hardening. Substations and the underground system are improved through system equipment replacement programs.
- **Infrastructure Redesign & Modernization (Section 9)** – This pillar includes projects which make more fundamental improvements to the electrical system and are focused on the longer term, such as conversion of the 4.8kV system to 13.2kV and upgrades of the subtransmission system to increase system capacity. These investments address longer-term grid needs as they replace aging infrastructure, relieve load constraints and convert the 4.8kV system to a modern grounded system at a higher voltage.

Section 5 also identified investment needs in the areas of Observability and Controls; Analytics and Computing Platforms; and Communications. Investments to support operating the grid more efficiently and closing these gaps are found in the fourth pillar.

- **Technology and Automation (Section 10)** – These programs and projects include investments to automate the entire distribution system and build out the telecommunications infrastructure to enable communication with widely deployed smart grid devices. Additional investments are earmarked for an operational technology roadmap that will enable integration of DER into the Company's system and enhance distribution planning processes, allowing the Company to forecast grid needs as customers adopt new technologies. Advanced technology and automation on the grid not only improves reliability but is also a key factor in enabling greater customer accessibility to the grid.

Over the next five years, DTEE will invest \$5.8 billion in strategic capital programs and projects. This level of investment will deliver improved reliability, reduced reactive cost and increased capacity to serve current and future load with reduced system risk.

The overall investment levels are shown in Exhibit 6.1.1, with more detail by pillar and program shown in Exhibit 6.1.2. These investments represent all of the capital investments.

Exhibit 6.1.1 Projected DTEE Five-Year Distribution Grid Plan Investments

Category		Capital Investments (\$ Millions)					
		2024	2025	2026	2027	2028	5-Year Total
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	\$415	\$399	\$368	\$348	\$345	\$1,877
	Customer Connections, Relocations and Others	\$282	\$295	\$314	\$334	\$355	\$1,580
Strategic Capital Programs (details in Exhibit 6.1.2)		\$906	\$995	\$1,134	\$1,302	\$1,485	\$5,821
Total Capital Investments		\$1,603	\$1,689	\$1,816	\$1,985	\$2,185	\$9,278

Exhibit 6.1.2 5-Year Investment Per Pillar with Most Significant Investment for Each

Pillar	5-Year Pillar Investment 2024–2028 (Millions)	Largest Investment Area	5-Year Program Investment 2024-2028 (Millions)
Tree Trimming	\$573	Enhanced Tree Trimming Program	\$573
Infrastructure Resilience and Hardening	\$1,639	Pole and Pole Top Maintenance and Modernization	\$773
Infrastructure Redesign and Modernization	\$2,537	4.8kV Conversion and Consolidation (including CODI)	\$1,498
Technology and Automation	\$1,645	Grid Automation	\$1,192

6.1.1 Investment Impact on Reliability

The investments detailed in the 2023 Distribution Grid Plan will provide significant customer benefits including improved safety as well as better reliability and resiliency during normal conditions and severe weather. These investments will also improve the operability of the distribution system, including the ability to accommodate new loads.

The investments in 2024-2028 detailed in the four pillars will significantly reduce the frequency (SAIFI) and duration (SAIDI) of customer outages. While the entire portfolio of strategic investments is needed to improve the grid, the primary drivers of reliability improvement over the next five years are the tree trimming program, pole top maintenance and modernization and automating the distribution system. Reliability projections are shown in Exhibits 6.1.1.1 and 6.1.1.2 and are shown through 2029 as the first full calendar year post 2028 investments. In summary:



- By 2029, All-weather SAIDI is projected to improve by 64% in normal weather,²⁹ improving from a fourth quartile baseline to second quartile performance. In addition to the projected average SAIDI, the range between all-weather SAIDI in favorable and unfavorable weather years is projected to decrease, primarily due to the impacts of the automation program, which will reduce the size of outage events.
- All-weather SAIFI during normal weather is projected to improve by 27% and achieve first quartile performance in 2029.

²⁹ A normal weather year typically has a quantity of Major Event Days (MEDs) that is close or equal to the average of the last ten years. DTE has experienced eight MEDs on average per year over the last ten years. There are exceptions, like the March 2017 windstorm, that can have only 1-2 MEDs but have an outsized impact on reliability metrics.

Exhibit 6.1.1.1 System All Weather SAIDI

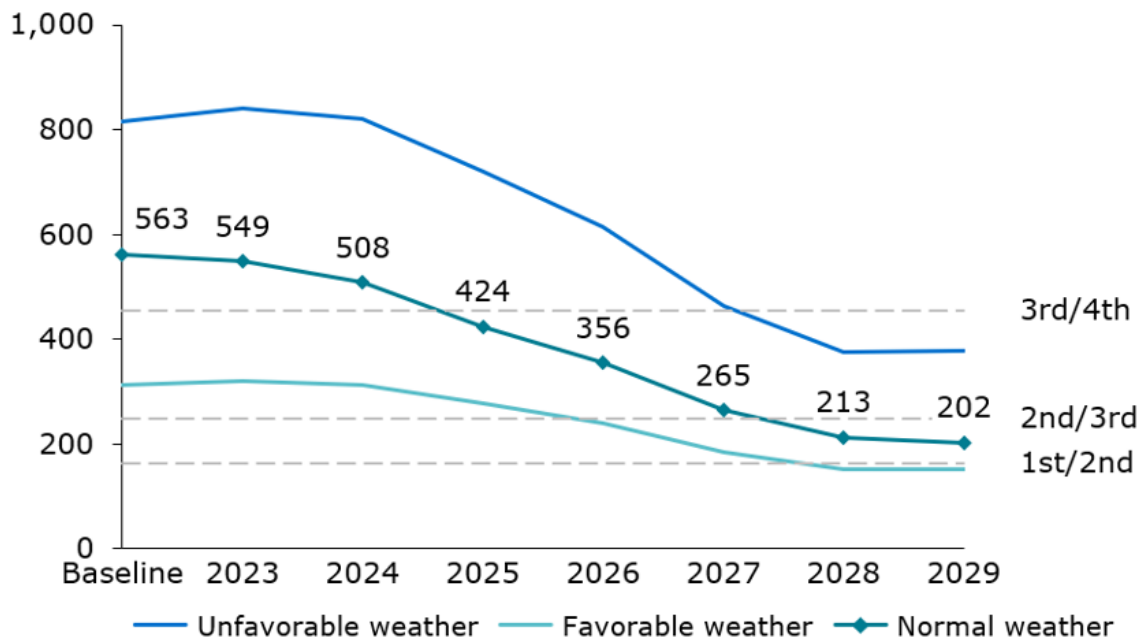
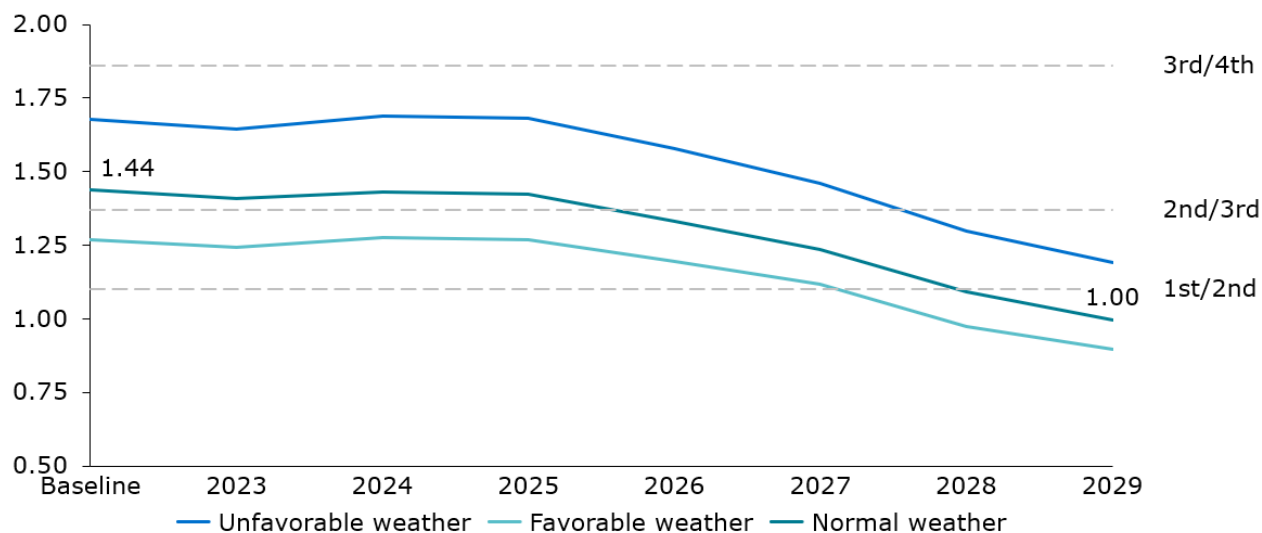


Exhibit 6.1.1.2 All Weather SAIFI



These reliability projections are based on a new reliability model and methodology the Company has updated since the filing of the 2021 DGP. This methodology uses a circuit level reliability projection

to model investment impacts and to generate a system level projection. More details on the methodology, as well as projections for non-MED reliability metrics are shown in Exhibit A.3 in Appendix A.

7 Pillar: Tree Trimming



Maintaining sufficient tree clearance from electrical equipment and lines is critical to ensuring safe and reliable power for customers. At present, nearly two-thirds of all outage minutes experienced (storm and non-storm) by DTEE customers are caused by trees damaging power equipment.

DTEE has taken deliberate action against tree interference by trimming to an enhanced specification known as the Enhanced Tree Trimming Program, or ETTP, since 2016. The ETTP is designed to reclaim right of ways, remove or reduce vegetation hazards from distribution infrastructure and properly define trim specifications for vegetation encroachment.

7.1 Methodology of Impact Analysis

DTEE created a control group of non-ETTP circuits to compare against ETTP circuits across four tree-related metrics: outage events, customers interrupted, customer-minutes interrupted and wire down events. The control group is used to negate the effects that weather and system variations could introduce into the performance metrics as both groups generally experience the same conditions each year. Performance is measured over the first four years post-ETTP work by calculating the percentage improvement between each year and the average of the three years prior to the work. The same methodology is used for the control group. The two groups are then compared to determine the relative difference of the ETTP group versus the control group.

7.2 Results: Consistent Improvement Across All Metrics

Below are results for the metrics measured in the impact analysis. These numbers indicate significant reductions in outage events resulting in improvements to ETPP circuit reliability, underscoring the effectiveness of reducing tree-related issues to enhance overall system performance.

7.2.1 Metric 1: Outage Events

First-year performance results indicate a significant reduction (62.1%) in tree-related outage events. Data for several years of the program can be examined in Exhibit 7.2.1.1 below.

Exhibit 7.2.1.1 Tree-Related Outage Event Difference: ETPP vs. Non-ETPP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETPP-Trimmed	1,549	1,228	754	298
Change in Outage Events for ETPP Circuits	-27.3%	-15.2%	+9.4%	+36.7%
Change in Outage Events for Non-ETPP Circuits	+34.8%	+53.4%	+60.5%	+77.3%
Difference in Number of Outage Events	-62.1%	-68.6%	-51.1%	-40.6%

7.2.2 Metric 2: Customers Interrupted

Tree-related customer interruptions were reduced in each year for the ETPP-trimmed circuits with a 66.3% reduction after the first year. Additional data is available in Exhibit 7.2.2.1. below.

Exhibit 7.2.2.1 Tree-Related Customer Interruption Difference: ETPP vs. Non-ETPP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETPP-Trimmed	1,549	1,228	754	298
Change in Customer Interruptions for ETPP Circuits	-46.7%	-44.8%	-38.9%	-24.6%
Change in Customer Interruptions for Non-ETPP Circuits	+19.6%	+31.8%	+25.7%	+27.8%

Difference in Number of Customer Interruptions	-66.3%	-76.6%	-64.6%	-52.4%

7.2.3 Metric 3: Customer Minutes Interrupted

Customer minutes interrupted showed a reduction for all years, with a 59.1% decrease after the first year. Additional data is available in Exhibit 7.2.3.1. below.

Exhibit 7.2.3.1 Tree-Related Customer Minutes Interrupted Difference: ETPP vs. Non-ETTP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETPP-Trimmed	1,549	1,228	754	298
Change in Customer Minutes Interrupted for ETPP Circuits	-51.8%	-37.3%	-25.9%	-32.8%
Change in Customer Minutes Interrupted for Non-ETTP Circuits	+7.3%	+25.0%	-12.3%	-6.4%
Difference in Number of Customer Minutes Interrupted	-59.1%	-62.3%	-13.6%	-26.4%

7.2.4 Metric 4: Wire Down Events

Tree-related wire down events decreased in all years of measurement, with a 53.0% reduction in the first year. Further data is available in Exhibit 7.2.4.1. below.

Exhibit 7.2.4.1 Tree-Related Wire Down Events Difference: ETPP vs. Non-ETTP Circuits

Years Post-Trim	1	2	3	4
Number of Dist. Circuits ETPP-Trimmed	1,549	1,228	754	298
Change in Wire Down Events for ETPP Circuits	-61.2%	-63.7%	-56.2%	-38.2%
Change in Wire Down Events for Non-ETTP Circuits	-8.2%	-3.7%	-17.3%	-29.5%

Difference in Number of Wire Down Events	-53.0%	-60.0%	-38.9%	-8.7%

7.3 Learning-based Improvements to Tree Trimming

DTEE has made several significant improvements to its tree trimming practices since the beginning of ETTP in the areas of scheduling, herbicide and efficiency in the field.

7.3.1 Scheduling

Tree trimming supports several workstreams (e.g., maintenance, trouble, and capital trimming) and DTEE has dedicated a team to improve the scheduling of these workstreams across the board. In the past, prioritizing and scheduling was disaggregated and often took place at the service center level. Currently, the tree trim scheduling team is developing an integrated scheduling tool that monitors all workstreams in a centralized manner, enabling the Company to schedule with the efficiency required for both customer and construction projects while staying on schedule with annual maintenance trimming.



7.3.2 An Industry-best Herbicide Program

Since 2018, the Company has used treatments instead of physical removal of vegetation from right-of-ways. DTEE's herbicide program includes foliar and basal herbicide treatments as well as a dormant stem treatment. These applications help control tree species with the potential to grow into electrical wires and reduce the cost of maintenance trimming by decreasing tree density over time. As tree density and brush height decrease, the electrical system will experience fewer tree-related outages and the right-of-way will become more accessible for overhead crews, allowing them to more quickly find and repair damaged wire or broken equipment.

7.3.3 Improved Efficiency Through Innovative Equipment

DTEE has partnered with its tree trim contractors on new ways to improve efficiency through innovative equipment, piloting of new equipment and utilization of specialty equipment in backyard areas and alleyways.

- **Boom-mounted Saw Pilot:** This new, insulated saw (one of only two in the world) allows for use in the energized zone near the wires. These saws can safely and quickly remove large tree branches without the need for climbing and rigging, saving significant amounts of time, improving safety and reducing the number of trimmers needed to accomplish the work.
- **Specialty Equipment in Backyard Areas and Alleyways:** By using mechanical mowers, contractors can clear brush and small trees, creating access for bucket equipment and making tree removal easier and less expensive. DTEE continues to actively investigate methods to eliminate manual labor through the use of specialized equipment to further enhance overall efficiency and productivity. For example, DTEE is exploring the opportunity to use cranes for tree removal. Cranes can allow for easier and safer tree removal, specifically when dealing with trees over electrical wires.



7.4 On-Cycle – Risk-Based Modeling

As the Tree Trim Program enters the final years of the surge (2024-2025), the Company is dedicated to continuing to find program improvements. One enhancement is identifying optimal cycle lengths for individual circuits through the implementation of new technology tailored to meet the unique needs of each circuit. DTEE is currently developing a risk-based, variable-cycle model that will leverage Light Detection and Ranging (LiDAR) data and internal data sources to help identify optimal trim cycles and high-risk areas. This model will allow the Company to improve its maintenance trimming cycle to be more targeted than the current five-year standard for distribution circuits. Adjusting cycle-lengths will improve trimming efficiencies and reliability benefits for customers.

After the surge is complete, DTEE will be able to implement its risk-based model, having established a standardized five-year cycle baseline for the entire service territory. During this interim phase, DTEE

will have the opportunity to validate the model outputs and pilot its findings for trim cycles. This model's introduction into annual planning is intended to maintain the system reliability enhancements achieved during the surge while gaining efficiencies and improving outcomes with a risk-based cycle.

7.5 Accessing the Local Workforce Through Growth and Outreach

DTEE primarily utilizes five contract tree trimming companies to supply an average of approximately 1,200 workers needed to execute the annual tree trim plan. Assuming average storm volume, this same supply of contractors will be essential to maintain through the end of surge. Currently, there are not enough qualified local tree trimmers to complete the surge program and maintain on-cycle trimming, so DTEE must hire crews from outside of its service territory to supplement the local workforce.



The Company's long-term plan is to create an adequate number of local, qualified tree trimmers and to eliminate the need to hire non-local crews. Having local tree trimmers available provides immediate support for storm trouble, supplies workers properly trained on the local vegetation management program and is more cost effective.

Since 2020, DTEE has supported two pilot initiatives aimed at increasing the local tree trimmer workforce and creating more employment opportunities for residents.

- **Pre-Woodsman Training Program (Pilot)** The Company has partnered with the city of Detroit, IBEW Local 17, Focus Hope, and its tree trimming contractors to develop and implement a training program to help generate qualified tree trimmers. The pilot academy was established within the city of Detroit to support accessibility for resident candidates and to encourage them to prepare for work as woodsmen. As of September 2023, the training program has graduated 148 candidates, 40% of which are Detroit residents.

- **Parnall Correctional Facility Outreach Program (Pilot)** DTEE has implemented a training program for tree trimming at the Vocational Village within the Parnall Correctional Facility in Jackson. This program was developed to allow returning citizens to directly enter the apprenticeship program upon leaving the correctional system. In selecting applicants, the Vocational Village administration placed significant emphasis on the individual's county of residence to ensure a reasonable commute to work once released. Graduates are paired with jobs upon completion of the program.



7.6 Conclusion

The Tree Trimming Program is one of the most important and impactful pillars in furthering the Company's commitment to improving system reliability and safety. The program has demonstrated significant decreases in system risk (specifically wire downs) and increases in reliability (fewer and shorter outages). Through completion of the surge and implementation of innovative risk-based modeling, DTEE will continue to yield proven reliability and safety improvements.

8 Pillar: Infrastructure Resilience and Hardening (Capital Replacement Programs)



DTEE is experiencing increasing challenges from its aging infrastructure and faces the need to upgrade and rebuild much of its equipment and facilities. The 2023 American Society of Civil Engineering (ASCE) report scored Michigan a cumulative C-, grouping it among states most in need of infrastructure investments. Among the fourteen categories ASCE analyzed, such as bridges, roads, schools and energy, Michigan received a D rating in Energy infrastructure³⁰. Demographic trends are mostly responsible for this situation. Michigan industrialized in the late 1800s and early 1900s and thereafter experienced robust population growth until the 1960s. As a result, much of its infrastructure (including DTEE's) was built during that period. Flat to declining population for the state and its major cities over the past 50 years made it financially challenging for government entities and utilities to replace this aging infrastructure. In response, DTEE focused on maintaining its existing distribution assets in a cost-effective manner in recent decades, expanding the distribution system when needed to meet demand, but leaving aged equipment in place to achieve affordability targets for its customers.

Replacement of this infrastructure can no longer be prudently deferred as these assets are now at, or nearing, the end of their useful life. Equipment manufacturers provide useful life expectations for their equipment representing the number of years a piece of equipment is expected to operate before it becomes unreliable and uneconomical to keep in service. Assets which meet or exceed their useful life fail more often and present safety and affordability concerns to customers as outage frequency and expenditures for reactive maintenance increase. It is critical that DTEE accelerates investment

³⁰ [Report-2023-MI-IRC-Final-WEB.pdf \(infrastructurereportcard.org\)](#)

into its Infrastructure Resilience and Hardening pillar to ensure its distribution system meets customer expectations for safety, reliability, power capacity and quality. Ramping up the Pole Top Maintenance and Modernization Program (PTMM) to make the grid more reliable, completing the 4.8kV Hardening program to improve safety and increase storm resiliency, and replacing aging, defective, obsolete, and otherwise at-risk infrastructure are all key parts of the strategy to improve service for customers.

The gaps assessment utilizing the DSPx framework discussed in Section 5 makes it clear that the foundation of the electrical grid is the physical grid infrastructure (e.g., poles). To improve the foundation of the DTEE electric grid, the Infrastructure Resilience and Hardening pillar focuses investments on the replacement of equipment that fails inspection; is defective and prone to premature failure; is at or nearing end of useful life; or is obsolete with limited availability of spare replacement parts. Investments in this program include a range of equipment replacements from poles and pole-top equipment to breakers and underground cable. Replacing this equipment is critical to ensuring the distribution system meets customer expectations for safety and reliability. For reference, Section 9 of the Company's 2021 DGP³¹ provides more detailed descriptions of capital replacement programs within the Infrastructure Resilience and Hardening pillar. The 2023 DGP report will highlight the major equipment types that support the distribution system and make up the largest portion of the investment in this pillar. Each of these equipment types has a replacement program with dedicated investment. Many of these programs, such as subtransmission disconnect switch replacement, will continue beyond 2028 due to the volume of equipment needing to be replaced or as additional issues or reliability needs are identified, and replacement is warranted.

8.1 Pole and Pole-Top Maintenance and Modernization Program (PTMM)

Approximately 70% of DTEE's infrastructure is overhead, and overhead equipment failures cause nearly 25% of all outages that customers experience. Poles and pole-top equipment are some of the most important and visible parts of the subtransmission and distribution grid, and are continually exposed to harsh conditions (e.g., ice, heat,



³¹ DTEE 2021 Distribution Grid Plan - [068t000000Uc0pkAAB \(site.com\)](#)

rain, lightning, sunlight and wind), causing them to degrade and weaken over time.

DTEE's Pole and Pole-Top Maintenance and Modernization Program (PTMM) inspects overhead circuits for poles and pole-top equipment that fail inspection and replaces them with modern equivalents with better materials that are more durable and reliable. Poles younger than 20 years are visually inspected for structural integrity and poles older than 20 years undergo rigorous physical testing that includes treatments to prevent decay (Exhibit 8.1.1). Poles that fail inspection are replaced with new poles of a higher class which are as much as two-times stronger at groundline and 20% better at withstanding high winds when compared to the poles being replaced. Pole tops are inspected to identify defective equipment (including wooden crossarms, porcelain cutouts and porcelain insulators) and any component that fails inspection is replaced with stronger fiberglass crossarms, polymer cutouts, and polymer insulators which have five to six times more mechanical strength than their wooden and porcelain counterparts (Exhibit 8.1.3). This new pole-top equipment is made of stronger materials, experiences less deterioration from weather elements, and can better withstand increasing storms and wind gusts, resulting in fewer equipment failures and customer outages.

DTEE's PTMM Program has received significant enhancements over recent years, including improving both pole testing and pole top inspections. These changes were made after benchmarking other Northeast and Midwest utility practices (Exhibit 8.1.2), reviewing the U.S. Department of Agriculture's Rural Utility Services (RUS) bulletin ("1730-121 USDA Rural Utility Service Wood Pole Inspection and Maintenance"), and conducting internal reviews of the Company's pole failure performance. The Company adopted physical testing for poles 20 years and older after reviewing the above sources, reviewing its own pole performance, and determining that below-grade pole decay has rarely been seen on poles installed less than 20 years ago. DTEE reviews these specifications bi-annually and makes changes as appropriate based on internal performance analysis and industry best practices.

Enhanced PTMM inspections have resulted in a two to three time increase in identification of poles that fail inspection and pole top equipment locations that need to be remediated on a per circuit mile basis. Because the PTMM program scope has grown over the last 12 months, the Company lacks specific performance data for reliability improvement from the improved PTMM program. The Company estimates a 30% reduction of multiple customer outage events in the first year post PTMM after analyzing performance from Customer Excellence³² and 4.8kV Hardening performance. Because



the number of pole replacements and overhead assets the PTMM program is remediating has increased, the Company is confident that the benefit to customers will be in the 30% improvement range and could in fact be higher in future years. The Company will continue to analyze this program, including the before and after reliability and wire down performance of circuits, and update its reliability improvement assumptions accordingly as more circuits are completed with the new PTMM standards.

DTEE's goal is to inspect poles on a 10-year cycle per the industry guidance discussed above as well as the MPSC Staff's recommendation in their "Utility Pole Inspection Investigation Staff Report" dated November 20, 2009. Over the next five years, to ensure testing and maintenance of the entire system in a timely manner, the Company plans to ramp up the PTMM Program to achieve this goal DTEE plans to increase its investments in the PTMM Program as a key lever to reduce overhead equipment-related failures and drive reliability improvements, reduce reactive and storm expenditures and improve the safety of the system by reducing wire downs.

³² The Customer Excellence (CE) program provides rapid solutions to small pockets of customers experiencing poor reliability on a circuit.

Exhibit 8.1.1 Pole Testing

Equipment	Rural Utility Services (RUS)	DTEE Specification
Pole	Physical testing on all poles 10+ years old	Physical testing on all poles 20+ years old

Exhibit 8.1.2 Utility Pole Benchmarking

	Company 1 Northeast	Company 2 Northeast	Company 3 Midwest	Company 4 Midwest
Inspection Practices	4-year pole and pole top inspection program	5-year pole and pole top visual inspection program	10-year pole test program 5-year visual inspection including pole top	10-year pole test program 5-year visual inspection including pole top

Exhibit 8.1.3 Pole Top Equipment Specifications

Equipment	Construction Specification (2019-Current)
Crossarms	Fiberglass crossarms (5x stronger, 60-year lifespan)
Insulators	Polymer insulator (6x stronger, longer lasting)
Cut-outs	Polymer cut-outs (6x stronger, longer lasting)

The PTMM Program modernized 1,562 circuit miles, replaced 4,537 poles and performed approximately 92,000 inspections in 2022. It is anticipated that the PTMM 2023 workplan will replace poles and pole-top equipment on approximately 1,000 circuit miles and replace approximately 3,300 poles (which includes eliminating the pre-2022 condemned pole backlog).

Exhibit 8.1.4 below shows that DTEE plans to invest \$773 million over the next five years in the PTMM Program. The 4.8kV Hardening Program miles inspected are included in this table because the

program also performs pole and pole top inspections to the same standard, and its work scope does not include the same circuits as the PTMM Program. PTMM is a standard utility industry program, and this program will continue indefinitely beyond the five-year span detailed in this grid plan.

Exhibit 8.1.4 Pole and Pole Top Program Future Investment

	2024	2025	2026	2027	2028	2024-2028 Total
PTMM Investment Projection (\$ millions)	\$121	\$121	\$151	\$192	\$188	\$773
Miles Inspected on PTMM	1,604	1,604	2,043	2,651	2,651	10,553
Miles Inspected on 4.8kV Hardening	145	296	154	-	-	595

8.2 4.8kV Hardening Program

The 4.8kV system built in Detroit and the surrounding communities, is the oldest part of DTEE's distribution network. Due to age and condition, these segments have a ~3.6 times higher volume of trouble events per circuit mile than non-Detroit areas. Additionally, there is a parallel electric system and a public lighting system in the city of Detroit that was built by the Detroit Public Lighting Department (DPLD) that is no longer being used and needs to be removed. This DPLD system includes arc wire, which is highly susceptible to wire downs and represents a public and employee safety hazard, co-located with DTEE's electric grid. The Company created the 4.8kV Hardening Program after receiving an order from the MPSC in Case No. U-18484 to develop a plan to address the DPLD arc wire.



The need to remove the arc wire, combined with the age and condition of the electric grid in the city of Detroit, has rendered general maintenance practices insufficient to achieve the safety and reliability results needed. In response, DTEE created its 4.8kV Hardening Program in 2018 to aggressively improve and upgrade the city of Detroit overhead infrastructure. The program delivers near-term, cost-effective results that improve public safety and address frequent outages through extensive system upgrades. The scope of the 4.8kV Hardening Program includes:



- Removing Detroit Public Lighting Department (DPLD) arc wire and distribution wire from Company-owned equipment and ensuring the remaining Company wires are left in a safe configuration
- Testing of all utility poles that have Company equipment attached; replacing or reinforcing as needed
- Replacing wooden crossarms with fiberglass crossarms and removing service lines to abandoned properties
- Trimming trees, as required, to support construction activities
- Performing any additional necessary work as dictated by field conditions
- Removing primary conductor in sparsely populated areas (deconductoring)

8.2.1 Results of the 4.8kV Hardening Program

The 4.8kV Hardening Program has hardened 1,464 miles between 2018-2023, including 475 miles in 2022, and plans for 345 miles in 2023. The program will have removed approximately 695 miles of arc wire (roughly 50% of the total co-located with DTEE equipment) from 2018-2023 including 224 miles in 2022 and plans to remove 173 additional miles in 2023.

Exhibit 8.2.1.1 4.8kV Circuit Miles Hardened

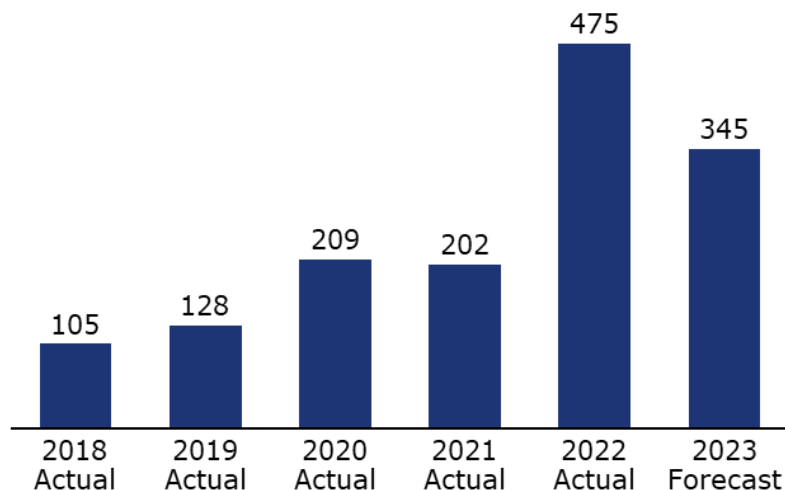
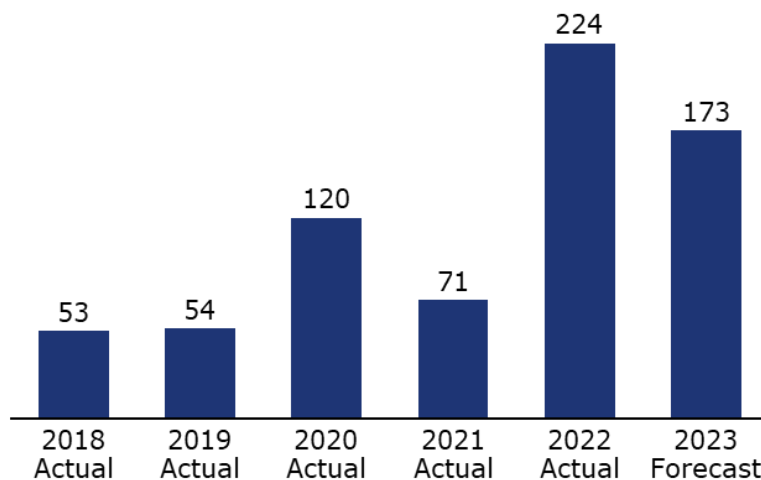


Exhibit 8.2.1.2 4.8kV Miles of Arc Wire Removed

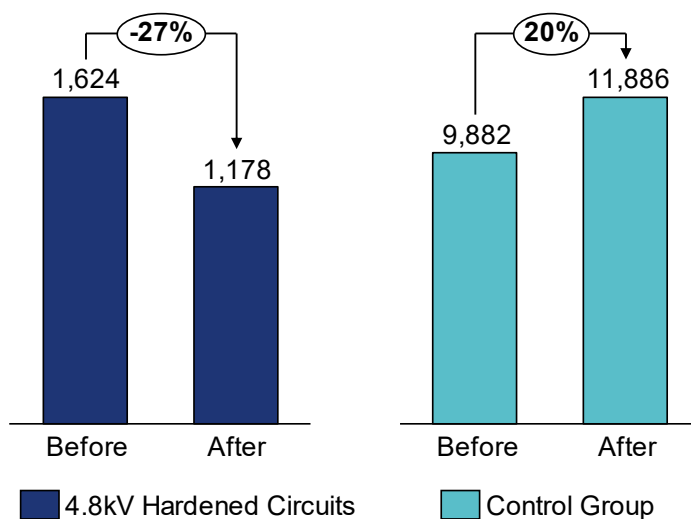


The program hardened approximately 183 circuits in the city of Detroit and surrounding areas through year-end 2022. The 144,222 customers impacted by these improvements represent nearly half of all DTEE's Detroit customers.

As a result of these investments, customers have seen noticeable improvements in the safety and reliability of the circuits they depend upon. When compared to a control group³³ of similar unhardened circuits, the 4.8kV circuits that were hardened experienced:

- a net 47% improvement in number of wire downs:

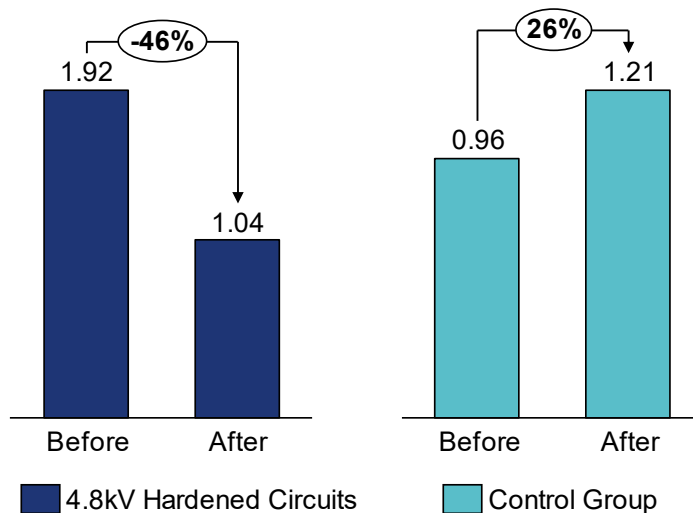
Exhibit 8.2.1.3 Wire Downs Before and After Hardening



- A net 72% reduction in All-Weather SAIFI:

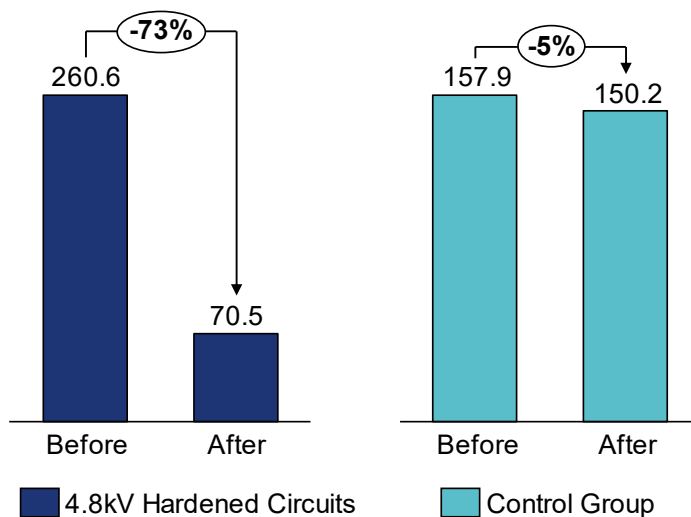
³³ A control group is used to negate the impacts of weather variation.

Exhibit 8.2.1.4 All-Weather SAIFI Before and After Hardening



- A net 68% improvement in SAIDI Ex-MEDs:

Exhibit 8.2.1.5 SAIDI Ex-MEDs Before and After Hardening



8.2.2. 4.8kV Hardening Technical Conference

On March 22, 2023, the Company hosted a technical conference sponsored by the MPSC Staff³⁴. The meeting was organized to discuss opportunities to improve the safety and resiliency of the 4.8kV system, as well as options to address the remaining DPLD arc wire. The conference examined:

- a) The benefits the 4.8kV Hardening Program has provided thus far
- b) 4.8kV Hardening Program alternatives: Several options were presented, including new alternatives consistent with the MPSC Order in case U-20836:
 - i. Arc Wire Removal
 - ii. Pre-Conversion
 - iii. Conversion
 - iv. Microgrids

Exhibit 8.2.2.1 4.8KV Hardening Alternatives

Program	Avg. Cost per Mile	Wire Down Reduction	SAIFI Reduction	SAIDI Reduction
Arc Wire Only	\$191k	-13%	-22%	-36%
4.8kV Hardening	\$353k	-26%	-44%	-72%
Pre-Conversion	\$1.7M	-90%	-85%	-85%
Conversion	\$2.7M	-90%	-85%	-85%
Microgrids	\$14.6M	-90%	-95%	-95%

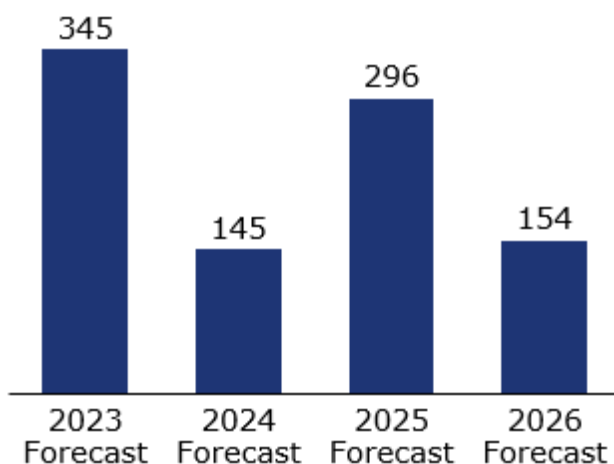
Analysis of Hardening alternatives and feedback from staff and stakeholders during the technical conference supports the Company's conclusion that the 4.8kV Hardening remains a cost-effective solution to quickly deliver safety and reliability improvements to customers in the Detroit area.

³⁴ DTE Electric 4.8kV Technical Conference - [DTE Electric 4.8kV Technical Conference \(michigan.gov\)](#)

8.2.3 Future of the 4.8kV Hardening Program

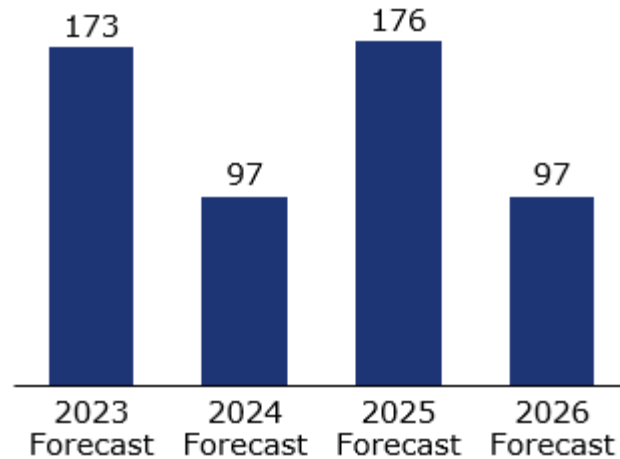
An estimated 550 miles of DPLD arc wire co-located with DTEE equipment will remain after year-end 2023. The 4.8kV Hardening Program plans to harden an additional 595 miles from 2024-2026 for a combined total of 2,059 miles from 2018-2026. The program also plans to remove an estimated 370 additional miles of arc wire from 2024-2026 for a combined total of approximately 1,065 miles removed, representing an estimated 86% of all arc wire collocated with DTEE equipment.³⁵ Upon completion of the 4.8kV Hardening Program in 2026, almost every pole will have been tested as well as having new cross arms and pole top equipment, which will provide customers with proven safety and reliability improvements.

Exhibit 8.2.3.1 Forecasted Circuit Miles Hardened



³⁵ Remaining collocated arc wire will be removed through 4.8kV conversion projects.

Exhibit 8.2.3.2 Forecasted Miles of Arc Wire Removed



8.3 System Equipment Replacement

System equipment plays a vital role in delivering electricity to customers, isolating and locating faults, and maintaining proper voltages and power quality on the electric system. For the system to operate as designed, this equipment should be not only functional, but in good condition physically and operationally. To optimize the consistency and reliability of these assets for our customers, DTEE uses an asset health analysis to routinely monitor and prioritize investments in replacement programs and identify the equipment that requires replacement. While some equipment replacements are integrated into circuit conversion projects, other assets such as those tied to the 13.2kV, 24kV, and 40kV are addressed through a separate replacement program for aged or defective equipment.

Over the next five years, DTEE plans to invest \$365 million in multiple distribution equipment categories. Exhibit 8.3.3.1 details the equipment asset types, quantities planned for replacement by year and projected investment needs over the next five years. A select group of these programs are discussed in the Section below.

Additional background on these assets can be found in Section 8: Asset Health Assessment on pages 151-210 of the 2021 DGP.

8.3.1 Overhead System Equipment

Automatic Pole-Top Switches (APTS): The function of the APTS is to sectionalize, isolate or connect portions of the subtransmission system. Failure of one of these switches has the potential to interrupt thousands of customers or result in significant operational constraints. There are 120 APTS in total that need to be replaced and, 69 of these will be replaced over the next five years.

SCADA (Supervisory Control and Data Acquisition) Pole-Top Devices: SCADA replacement targets two of the equipment types that have experienced high rates of failure – Eaton Form 3 reclosers and Bridges pole-top switches (PTS). Failure of these devices will result in reduced system operability and can cause customer interruptions at a circuit level.

An overhead three-phase recloser is a sectionalizing device that is located at key points on overhead distribution circuits. It acts like a circuit breaker, opening under detection of high current due to a downstream fault, such as a tree branch across two phases. A distribution SCADA PTS allows the System Operations Center (ESOC) to remotely reconfigure the grid to restore customers by isolating faults and/or transferring load to adjacent circuits during both planned and unplanned outages.

The program will replace 154 of these devices over the next five years.

Steel Pole Highway Crossings: DTEE equipment has been subject to incidents that resulted in the collapse of overhead freeway or highway crossing power equipment. This program was developed to replace wood poles with steel poles at these crossings as part of a multi-year program that is expected to replace and rebuild 53 crossings over the next five years.

8.3.2 Underground System Equipment

System Cable: System cable is a specific type of cable designed and used for underground distribution and subtransmission on the Company's primary electric system. System cable consists of large diameter cable surrounded by insulation, and it is installed underground in vaults and ducts between manholes. Sixty-four percent of system cable, or approximately 2,050 miles, is at or near the end of useful life, and 28% is a candidate for replacement based on the findings in the asset health assessment. Approximately 70 miles of system cable are planned for replacement over the



next 5 years. DTEE is increasingly concerned about the level of failure-risk posed by the age and condition of system cable because of the impact a system cable failure has on the overall system. When system cable fails, it reduces the level of redundancy of the grid and increases the risk of long duration customer outages.

Underground Residential Distribution Cable (URD): URD is a specific type of cable designed for underground residential use on the Company's secondary electric system. URD consists of small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or installed inside conduit. Because underground repairs can take significant amounts of time to fix, URD systems are often (but not always) looped so there are two paths to feed customers in case one cable fails. Forty-one percent of URD cables (about 4,500 miles) are candidates for replacement based on findings of the Company's asset health assessment, and 320 miles will be replaced over the next five years. Currently, the system averages approximately 1,000 URD failures per year, creating potential for extended outages when concurrent failures occur on the same URD loop.

8.3.3 Substation Equipment

Breakers: A circuit breaker is an electrical switch designed to isolate faults that occur on substation equipment, buses or circuit positions. Its basic function is to interrupt current flow after a fault is detected to minimize equipment damage due to high fault currents and to isolate the faulted asset from the electrical system. A failure of a circuit breaker can cause outages on multiple circuits and could reduce system redundancy for an extended period during repairs. Depending on the extent of the failure, and possible adjacent collateral damage, thousands of customers could be impacted for an extended duration. The Company has approximately 6,000 breakers on the electrical distribution and subtransmission systems. Sixty percent of all breakers are beyond expected useful life and 53% of all breakers are candidates for replacement based on the findings in the asset health assessment. Current plans are to replace 167 breakers over the next 5 years. To the extent possible, breaker replacements are coordinated with other capital or maintenance work to reduce costs and minimize the overall time the equipment is out of service. In most cases, breaker replacements include relay replacements to make the breaker SCADA controllable and to increase the penetration rate of substation remote monitoring and control capability. This is expected to bring significant customer benefits from improved substation operability.

Substation Regulators: Regulators are used to maintain voltages within a normal range. Replacement will allow for proper voltage regulation and avoid out-of-range voltages that damage customer equipment or cause reliability problems. Fifteen units will be replaced in the next five years.



Subtransmission Disconnect Switches:

Subtransmission disconnect switches are used to manually sectionalize and provide isolation points on the electrical system for operational or maintenance purposes. Failures of disconnect switches during operation, when operators attempt to open or close a disconnect manually, can lead to safety hazards, reduced system operability, and force additional equipment to be taken out of service to allow critical work to continue. One hundred and three subtransmission disconnect switches will be replaced in the next 5 years.

Circuit Switchers: Circuit switchers connect the transmission system (120kV) and the subtransmission system (40kV) to the primary side of a substation power transformer. The purpose of the circuit switchers is to protect substation equipment from damage caused by excess fault current. It is a smaller, less expensive alternative to a circuit breaker. Thirty circuit switchers will be replaced over the next 5 years. Switchers identified for replacement are prioritized based on risk of failure and inadequate equipment sizing.

Batteries and Chargers: DC Systems including batteries and chargers are used to provide reliable power to trip equipment during fault conditions. Failure of these systems would result in significantly longer duration faults, greater damage to equipment, larger outages and increased hazards due to the inability to clear faults. To maintain proper operating conditions at substations, batteries and chargers must be replaced when they reach end-of-life.

Exhibit 8.3.3.1 System Equipment Replacement Programs

	Investment (\$M) and Quantity by year					
System Equipment	2024	2025	2026	2027	2028	2024-2028
Subtransmission OH Bypass for PTS Maintenance	-	-	\$1.5	\$1.5	\$1.5	\$4.5
<i>units</i>	-	-	2	2	2	10
40 kV Automatic Pole Top Switch	\$5.0	\$5.0	\$5.8	\$5.8	\$5.8	\$27.3
<i>units</i>	12	12	15	15	15	69
Steel Pole Highway Crossings	\$5.0	\$5.0	\$5.0	\$5.0	\$5.0	\$25
<i>units</i>	9	8	12	12	12	53
Disconnects	\$3.0	\$3.0	\$3.0	\$3.0	\$3.0	\$15.0
<i>units</i>	22	22	21	20	18	103
Switchers	\$1.9	\$1.9	\$1.9	\$1.9	\$1.9	\$9.5
<i>units</i>	6	6	6	6	6	30
Breaker	\$14.3	\$15.0	15.0	15.0	15.0	\$74.3
<i>units</i>	35	36	33	32	31	167
System Cable	\$21.4	\$20.1	\$20.0	\$20.0	\$20.0	\$101.5
<i>miles</i>	17	17	17	17	17	85
URD	\$15	\$15	\$15	\$15	\$15	\$75
<i>miles</i>	70	67	64	61	58	320
SCADA Pole Top Device	\$1.8	\$2.0	\$2.3	\$2.6	\$5.2	\$13.9
<i>units</i>	22	24	26	28	54	154
Substation Regulators	\$0.8	\$0.8	\$0.8	\$0.8	\$0.9	\$4.2
<i>units</i>	3	3	3	3	3	15
Batteries and Chargers	\$2.5	\$3.0	\$3.0	\$3.0	\$3.0	\$14.6
<i>units</i>	75	89	74	74	74	386

8.4 Major Event Risk

Major event risk considers the likelihood and impact of the complete loss of a substation, which can impact a significant number of customers (thousands) for an extended duration (a couple of days). Risk is greatest when there is a combination of at-risk assets and the inability to transfer load when a failure does occur.

DTEE developed the major event risk model to identify areas of the system that are least resilient to a large failure at a substation. The model quantifies the relative substation outage risk scores and is used to help prioritize capital investment required to reduce this risk. Reduction in major event risk is one of the impact dimensions of the Global Prioritization Model (GPM) described in Section 12.1

Since the beginning of 2022, DTEE has experienced 96 major events on the system. These events have caused loss of power for anywhere from a few hundred customers to over 10,000 customers. One example of a major event in 2023 occurred at Snover substation, a single transformer, two circuit substation. The single substation transformer failed, resulting in loss of load for all customers served from the substation. The load of the circuits could not be transferred to neighboring circuits due to the configuration of adjacent DTEE circuits and because the other adjacent circuits are owned by other electric providers. The Company's short-term solution was to deploy portable distributed generators to serve the load of the two circuits. The medium-term solution required the Company to install a portable substation while permanent repairs were made at Snover substation. This example highlights both the significant challenges to addressing a major event failure and the important role the mobile fleet program plays in restoration of service to customers.

8.5 Programs to Address Major Event Risk

The major event risk model provides a framework for DTEE to measure risk reduction resulting from investments. There are four targeted investment areas to reduce major event risk: underground and substation equipment replacement, substation risk projects, station upgrades and the mobile fleet program, which are described below.

Underground and substation equipment replacement (discussed in more detail Section 4.3)

Replacement of at-risk cables and breakers both at substations and on the subtransmission system provides risk reduction by reducing the probability of failure of key substation equipment.

Substation risk projects

Projects in this category generally replace aging, at-risk equipment to reduce the probability of a failure. The most common substation risk project is switchgear replacement. Switchgear is a term for an enclosure with breakers, relays and wiring. A breaker or cable failure in a switchgear can take out multiple circuits at once. Projects target at-risk switchgear with known modes of failure to reduce the risk of a major outage. Projects are prioritized where deployment of mobile fleet assets is limited and cannot restore the entire substation load; in other words, customers will be out for more than 24 hours in the event of a failure. Other projects in this category include the Flood Defense Program, which targets substations that may be prone to flooding due to their location and installs equipment such as pumps to avoid equipment damage from water.

Station upgrade projects

This program focuses on relays and at-risk breakers at subtransmission facilities which convert voltage from transmission levels to our 24kV or 40kV subtransmission voltages. Failures on our subtransmission system have the potential to cause outages to one or more entire substations. Proactive replacement of these assets reduces long-term emergent costs associated with these equipment failures and reduces the risk of large outages.

Mobile Fleet Program

These investments expand the fleet of mobile generation, including portable generators, portable switchgear, portable substations, portable ISO equipment, portable poles, energy storage trailers and the controls that allow these assets to work together cohesively during planned and emergency events. These tools offer multiple operational benefits including decreasing restoration time for substation load that can't be feed from adjacent substations/circuits, supporting substations on a single contingency³⁶ to avoid outages, and providing the ability to facilitate the repairs of the failed equipment inside the substation while customers remain energized. Mobile distribution equipment is

³⁶ A single equipment failure will cause a large substation outage.

also used to support customers during planned work. Exhibit 8.5.1 shows a portable substation and mobile generator which are part of the fleet.

Exhibit 8.5.1 Portable Substation and Mobile Generator



In addition to the investments above targeted at reducing major event risk, investments in the Infrastructure Redesign and Modernization pillar (see Section 9) will also reduce major event risk by both replacing aging at-risk equipment and adding capacity to the system to enable load transfers so that single failures do not create large customer outages. For example:

- 4.8kV conversions – provide increased capacity and allow for decommissioning of aging substation equipment.
- Subtransmission redesign – station upgrades involve the installation of larger transformers, capacitor banks and associated equipment that will provide additional capacity.

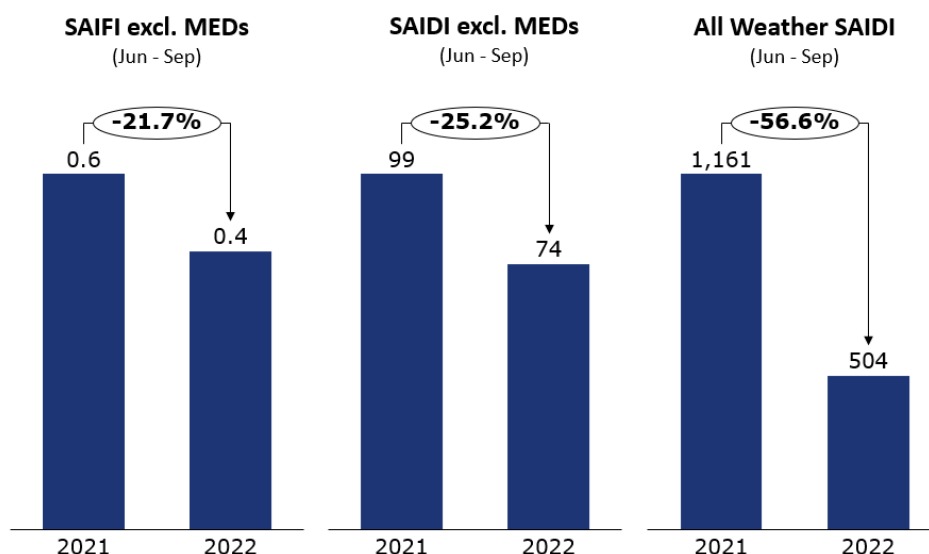
8.6 Short Cycle Maintenance Programs for Poor Reliability Circuits

While DTEE has multiple comprehensive equipment maintenance and replacement programs, these programs must plan their work far in advance to ensure proper planning and execution. The Company's electric distribution grid is vast with over 30,000 overhead circuit miles. At times, circuits or isolated pockets on circuits experience reliability or power quality issues that need to be addressed but are not on the current year's plan for the Company's larger and more comprehensive programs. Short cycle maintenance programs provide regional engineers with the flexibility to quickly identify the root causes of these issues and to create custom solutions for the affected customers and communities.

DTEE has two primary short cycle maintenance programs for poor reliability circuits: Customer Excellence (CE), and Frequent Outage (CEMI).

These two programs have recently undergone a change in how their work is selected and prioritized. In 2021, after experiencing a period of historic summer storms, the Company created a new process called Pre-Storm Season Strengthening (PS3) to identify circuits with characteristics that make them prone to failure during storms. Circuits identified through this process are assigned to each of the Company's programs and our short cycle maintenance programs now receive their work plans from this circuit evaluation process. PS3 circuits that were assigned to CE and Frequent Outage (CEMI) saw significant improvements in SAIDI and SAIFI during summer storm months in 2022 as shown below.

Exhibit 8.6.1 CE & CEMI Pre-Storm Strengthening Reliability Improvements



8.6.1 Customer Excellence Program (CE)

The CE program was established to provide rapid solutions to small pockets of customers experiencing poor reliability. These customers are identified as experiencing four sustained outages (SAIFI > 4.0), or nine momentary outages (MAIFI > 9.0) per year. The prioritization method for the CE program relies on Advanced Metering Infrastructure (AMI) data to identify these customers on a rolling 12-month basis to address issues more rapidly than other programs which rely on the annual analysis of reliability events. In addition to reliability event data, the prioritization also includes an evaluation of time passed since the area's last tree trim was completed, any other near-term planned work on the circuits, and customer complaints.

Upon identification of a circuit that meets the CE prioritization criteria, the Company conducts a field patrol to understand both equipment and tree conditions. After the patrol, the scope of work is developed for both equipment-related and tree-related problems. In addition to the defective equipment replacements and tree trimming, the scope of work also includes checking operating equipment to ensure it is functioning properly, conducting fault studies to ensure fuses are properly sized, and installing additional equipment, such as reclosing devices and animal guards, to prevent future outages. The Company also performs CE work on pockets of its subtransmission system that are experiencing reliability issues. On average, the solutions require investments between \$60,000 and \$80,000 per circuit to implement.

The Customer Excellence Program will continue beyond five years, though it may decline in investment levels over time as the Company's more comprehensive programs are executed and the grid is brought to an improved operating state.

8.6.2 Frequent Outage Program (CEMI)

The Frequent Outage Program, also known as CEMI (Customers Experiencing Multiple Interruptions), performs improvements to either portions of a circuit (customer pockets), or entire circuits as appropriate. The primary distinctions between the CE and the CEMI programs are that circuits are normally selected for the CEMI program based on three-year average circuit SAIDI and SAIFI performance, MPSC complaints, and regional expertise on customer needs. In addition, the scope of work performed under the CEMI program is more comprehensive, and typically requires investments between \$250,000 and \$300,000 per circuit to implement.

Frequent Outage Programs (CEMI) will continue beyond five years, though they are likely to decline in investment levels over time as the Company's more comprehensive programs are executed and the grid is brought to an improved operating state.

9 Pillar: Infrastructure Redesign and Modernization



Infrastructure Redesign and Modernization is the investment pillar that supports the long-term grid investments in DTEE's 2023 Distribution Grid Plan. The goals of the projects and investments in this pillar are to enhance safety, reliability and resiliency, and add capacity. These projects include elimination of loading constraints, redesign and rebuild of the subtransmission system, and conversion and consolidation of the 4.8 kV and 8.3 kV systems to the higher 13.2 kV distribution voltage level.

As identified in Section 5.1, the lack of capacity on significant portions of DTEE's distribution and subtransmission systems must be addressed to provide operational redundancy, which is a key element for improving reliability and resiliency. Adding capacity will also accommodate customers' increasing adoption of DER and EVs. This section provides a detailed description for each of the infrastructure redesign projects planned for the next five years. This area of redesign and modernization is expected to grow in importance as DTEE continues to focus on the grid of the future and the role of increased electrification and DER.

9.1 Distribution Load Relief Projects

Assessment of customer load and available capacity at the system, substation and circuit levels is necessary to ensure that sufficient distribution system capacity exists to serve demand. This assessment also helps to identify potential constraints and impact on individual pieces of equipment. Beyond the existing loading conditions, there are areas within the system where the peak load is expected to increase as a result of load from new customers, increased load from existing customers, including increased electrification load, or customers relocating geographically from one area of the system to another. In some areas, existing load conditions have prevented DTEE from supporting

new load requests or doing so within customer requested timeframes. It is critical for the Company to identify expected capacity needs well in advance of the expected load increase to complete planning, siting, permitting, ordering of long lead time equipment, and construction of necessary infrastructure in time to provide the expected service and associated reliability to customers.

Capacity needs are reviewed from two grid conditions: normal state and contingency state. The normal state exists when all equipment and components are in service and operating as designed. The contingency state describes the localized grid condition that exists when there is a temporary planned equipment shutdown, the loss/failure of a component of the electric power system (e.g., subtransmission line), or the loss/ failure of individual equipment (e.g., transformer, system cable, or breaker). Under contingency conditions, equipment in the rest of the system often sees an increase in load to compensate for the out-of-service equipment, therefore requiring additional capacity above what is needed for the normal state. Exhibit B.1.1 in Appendix B displays diagrams depicting normal state and contingency state at a substation.

Under the two capacity states, most components and equipment are rated for day-to-day operation and emergency operation. These ratings are calculated to support the viability of an asset throughout its expected useful life. Operating equipment above its designated ratings can in some cases cause immediate failure or accelerate end-of-life.

- The **day-to-day** rating (for normal state conditions) is the load level that the equipment can be operated at to achieve its expected life span.
- The **emergency** rating (for contingency state conditions) is typically higher than the day-to-day rating and indicates the load level at which the equipment can operate for short periods of time. Operating at the emergency rating can add stress to the equipment and shorten its lifespan. If a piece of equipment exceeds its emergency rating, equipment failure may occur, and DTEE's System Operations Center takes steps to transfer or shed load.
- Substations also have a **firm** rating, which is the maximum load the substation can carry under a single contingency condition and is based on the lowest emergency rating of all the substation equipment that is required to serve the load. Note that it is possible to operate a substation over firm in a normal configuration without damaging equipment, provided it is configured to interrupt power and outage customers for any failure of the incoming feed or

within the substation, and restoration of customer load is restricted until all repairs have been completed.

- Circuits are operated under a Distribution Design Order (DDO) limit, a specific form of a distribution standard intended to maintain system capacity and operational flexibility. For example, the DDO rating for 13.2kV circuits is 8MVA, whereas a typical emergency rating is approximately 12 MVA. These DDO ratings allow for serving half of an adjacent circuit in the event of an outage while still remaining under the emergency rating for that circuit. The DDO limit is comparable to the Rural Utilities Service Standards, which are issued and maintained by the United States Department of Agriculture (USDA), which require system planning to account for planned and emergency load shifting. These are the minimum standards required for Rural Co-operatives to receive USDA financial assistance for projects and provide for ensuring capacity for switching as a baseline standard.

To ensure that expected load growth can be served within the equipment ratings, DTEE's distribution planning engineers conduct annual Area Load Analyses (ALA). These analyses include a review of past loading data and known new loads, verification of equipment ratings and substation firm ratings, system conditions and configurations, and input from large customers and municipal officials about potential development. Based on DTEE's 2022 ALA study, approximately one-third of distribution substations have some level of loading constraints, either within the substation or on their circuits. There are two major impacts of operating substations over their firm rating. The first limitation, during high loading periods, normally the summer season, occurs when an equipment failure in a substation that is over firm can lead to a customer outage until the equipment is repaired, load is jumpered to a neighboring substation, or another mitigation plan is enacted such as deploying a mobile generator. In some areas of the distribution grid with limited capacity, the option of transferring load to an adjacent substation may not be available. The second limitation is that substations over firm have limited capacity for new load. Under a scenario with increased electrification, capacity constraints are expected to get more severe over time. In addition, it can take several years to resolve loading issues if a new substation and circuits are needed to provide relief.

For areas experiencing loading constraints, capital investment projects are developed to add or upgrade overhead or underground lines, expand or build new substation capacity, or both. A strategic load relief project is often the result of a combination of general load growth, specific customer connection requests, aging infrastructure replacement and reliability improvement needs. Some

strategic load relief projects, such as building a new substation, may have the added benefits of mitigating substation risk at neighboring substations and improving overall reliability for the area.

9.1.1 Load Relief Prioritization

To address the approximately one-third of DTEE's distribution substations that have loading constraints, DTEE's engineering team assesses loading constraints and criticality to develop priorities and projects to eliminate the loading issues. These projects are then input into DTEE's Global Prioritization Model as part of the Company's capital planning process.

This load relief prioritization methodology has been enhanced in recent years and is now based on five variables including distribution circuits exceeding Distribution Design Order (DDO) limits:

- **Substation equipment overload** (peak load nearing or exceeding substation equipment day-to-day ratings or nearing substation equipment emergency ratings) — The limiting element is often a substation transformer or regulator, but it can sometimes be other secondary equipment at the substation such as conductor, system cable, bus bar, or breaker. A score is given to substations based on the ratio of load to rating with the highest score representing the most severe overload condition.
- **Substation Over Firm** (peak load exceeding substation firm rating under contingency conditions) – A score is given to substations that experience varying degrees of megavolt-amperes (MVA) load over their firm ratings. Under contingency conditions, any load over a substation's firm rating represents customers that cannot be served by that substation.
- **Circuit equipment overload** (peak load exceeding circuit equipment day-to-day ratings or exceeding circuit equipment emergency ratings) - The limiting element for distribution circuits is often the underground cable exiting the substation, but it can also be other equipment such as reclosers or overhead conductors. A score is given to each circuit based on the ratio of load to rating with the highest score representing the most severe overload condition. A circuit also receives a score if the distribution transformers on the circuit are exceeding their day-to-day rating. The circuit scores are then summed for each substation.
- **Strong load growth prospect** – The overall score given to a substation is increased if the substation has known load growth.

- **Circuit over DDO** – A score is given to substations with circuits that exceed the Distribution Design Orders (DDOs), which is 8MVA for 13.2kV circuits and 3MVA for 4.8kV circuits. While operating within these standards is important to provide flexibility and improve restoration options, the scoring for the Circuit over DDO dimension is given less weight than other loading constraints.

The final priority ranking of distribution load relief is a combination of the previously stated five variables. Exhibit 9.1.1.1 lists the highest ranked substations based on this methodology with checkmarks indicating applicable variables. Engineering reviews the constraints and develops projects to eliminate the loading issues.

Exhibit 9.1.1.1 Top 25 Highest Ranked Load Relief Substations Overview

Index	Substation	Voltage (kV)	Community	Substation Equipment Overload	Substation Over Firm	Circuit Equipment Overload	Strong Load Growth Prospect	Circuits over DDO	Project Planned
1	St. Antoine	13.2	Detroit			✓	✓	✓	✓
2	Alfred	13.2	Detroit			✓	✓	✓	✓
3	Garfield	4.8	Detroit			✓	✓	✓	✓
4	Cato	13.2	Detroit			✓	✓	✓	✓
5	Temple	13.2	Detroit			✓	✓	✓	✓
6	Madison	4.8	Detroit			✓	✓	✓	✓
7	Jewell	13.2	Washington	✓	✓	✓	✓	✓	✓
8	Walker	4.8	Detroit			✓	✓	✓	✓
9	Cody	13.2	South Lyon		✓	✓	✓	✓	✓
10	Hawthorne	4.8	Dearborn Heights		✓	✓		✓	✓
11	Cato	4.8	Detroit			✓	✓	✓	✓
12	Amsterdam	4.8	Detroit			✓	✓	✓	✓
13	Daly	4.8	Dearborn Heights	✓	✓	✓		✓	✓

Index	Substation	Voltage (kV)	Community	Substation Equipment Overload	Substation Over Firm	Circuit Equipment Overload	Strong Load Growth Prospect	Circuits over DDO	Project Planned
14	Roseville	4.8	Roseville	✓	✓	✓		✓	✓
15	Howard	4.8	Detroit			✓	✓	✓	✓
16	Golf	13.2	Macomb		✓	✓		✓	✓
17	Cypress	13.2	Marysville	✓	✓	✓	✓	✓	✓
18	Utica	4.8	Utica		✓	✓		✓	✓
19	Shaw	4.8	Imlay City	✓	✓	✓			✓
20	Slater	4.8	Brockway	✓	✓	✓		✓	✓
21	Wixom	13.2	Wixom		✓	✓	✓	✓	✓
22	Grayling	13.2	Shelby		✓		✓	✓	✓
23	Boyne	13.2	Macomb		✓	✓	✓	✓	✓
24	Snover	4.8	Snover	✓	✓	✓			✓
25	Goodison	13.2	Oakland Twp		✓	✓	✓	✓	✓

9.1.2 Consideration of Non-Wire Alternatives

To resolve the substation loading constraints described earlier, typical investments include conversion of a 4.8kV substation to higher voltage, or a substation loading project for an overloaded 13.2kV substation. In addition to these standard projects, which often take 5 or more years to engineer and construct, DTEE



continues to investigate non-wire alternatives (NWAs) through the implementation and analysis of a set of NWA pilot projects. NWA projects use a set of technologies that include solar energy, battery storage, and geo-targeted energy waste reduction and demand response (EWR/DR). NWA projects in some circumstances can provide targeted load relief to the electrical system in the short or even longer-term. To determine which load relief grid needs are candidates, DTEE has developed a screening process which reviews the specific factors including the project type, magnitude and timeline for the needed load relief, availability of contingencies, and cost of alternatives (specifically traditional alternatives). The screening process also takes into account the location of the site to evaluate if there is available space to implement NWA solution. If a substation or distribution circuit is identified as a potential candidate for NWA through the screening process, planning engineers work with technology and EWR/DR experts to evaluate detailed designs.

DTEE first identified a set of NWA projects in the 2021 Distribution Grid Plan, each addressing different opportunities and challenges of specific NWA technologies. Currently, these projects are in various stages of engineering, design and construction. Early lessons learned from the NWA projects have reinforced the importance of developing standard designs and creating operations and maintenance instructions for the new equipment during the pilots. As an example, the standardization of the site plans and procedures when combined with the flexible mobile battery trailer systems developed from the Omega project is promising a much more efficient deployment at Port Austin and other future sites. Also, planning for increased lead times caused by vendor driven variability in equipment, software, and availability of parts due to global supply chain issues is critical to meeting

schedules with new technology. Finally, existing EWR and DR programs, with additional marketing and outreach, show higher levels of customer engagement than expected or experienced with less targeted efforts.

Further detail on these projects is discussed in Section 10.1 Grid Automation. Once the projects are implemented, learnings will be collected from these and other utility projects, and DTEE will leverage these learnings to continue to refine its criteria, develop new tools, and advance the overall process for pursuing NWA as part of the distribution planning process. The summary of NWA project learnings will be included in the 2025 DGP.

9.1.3 Projects to Address Distribution Loading

The projects including scope of work that are planned to address load relief for the highest ranked substations are listed in Exhibit B.1.2 in Appendix B. In addition to the highest ranked substations, there are other planned projects addressing load relief along with additional project drivers. These projects are shown in Exhibit B.1.3 in Appendix B. The projects that provide load relief typically include building or expanding substations, replacing substation transformers or other equipment, and establishing new distribution circuits to take load from existing overloading circuits and substation areas.

The projected costs and timeline for load relief projects are shown in Exhibit B.1.4 in Appendix B. This exhibit excludes the CODI and 4.8 kV conversion projects that provide load relief, as the projected investment for those projects is listed in 4.8 kV Conversions, Exhibit 9.3.5.1. DTEE has based the cost and timeline estimates for the identified projects on the best knowledge and information known today.

The identified load relief projects are planned based on DTEE's current assessments of area load growth and system loading conditions. Future area load growth is constantly evolving due to changes in general economic trends, utilization of demand response and energy efficiency measures, and changing customer trends such as adoption of EVs. Despite changing market dynamics, DTEE has a solid fundamental understanding of load growth in the near term and has a strong track record of forecast accuracy. Adoption of emerging technologies, specifically the adoption of electric vehicles, will surely bring

complexity to the forecast. To address this, DTEE is developing forecasting tools to provide insight into system requirements at the feeder-level. These solutions will monitor adoption of emerging technologies and forecast their impact on load on an hourly basis across the system. More information on planning and forecasting tools can be found in Section 10.2 Operational Technology Roadmap.

Based on current planned projects, DTEE estimates the annual capital investment on load relief projects as shown in Exhibit 9.1.3.1.

Exhibit 9.1.3.1 Projected Load Relief Capital Investment

	2024	2025	2026	2027	2028	Total Investment 2024-2028
Load Relief Capital Investment (\$ million)	\$47	\$75	\$59	\$100	\$100	\$381

9.2 Subtransmission Redesign and Rebuild Program

The subtransmission system serves as a vital grid link between the ITC transmission system and the DTEE distribution system. A station is a facility where high voltage from the transmission system is stepped down to 24kV, 40kV, or 120kV subtransmission voltage. 120kV radial lines that serve general purpose substations are transmission lines owned by the ITC (International



Transmission Company). DTEE owns 120kV subtransmission radial lines that serve customer dedicated substations. The 24kV system primarily serves 4.8kV substations and as the 4.8kV system is converted to higher system voltage, much of the 24kV subtransmission system will be eliminated. The subtransmission system is designed to provide redundant sources to distribution substations, which then directly serve circuits and customers. This redundancy provides continuity of service to customers even during a planned or unplanned equipment outage, also known as a contingency situation. DTEE's

subtransmission includes both radial and network elements. The radial configuration, called a trunk line, has one source station and can feed one or multiple distribution substations. The network configuration, called a tie line, has multiple source stations and can feed multiple distribution substations. Exhibits 9.2.1 and 9.2.2 below illustrate a trunk line and a tie line.

Exhibit 9.2.1 – Trunk Line Diagram Example (Radial)

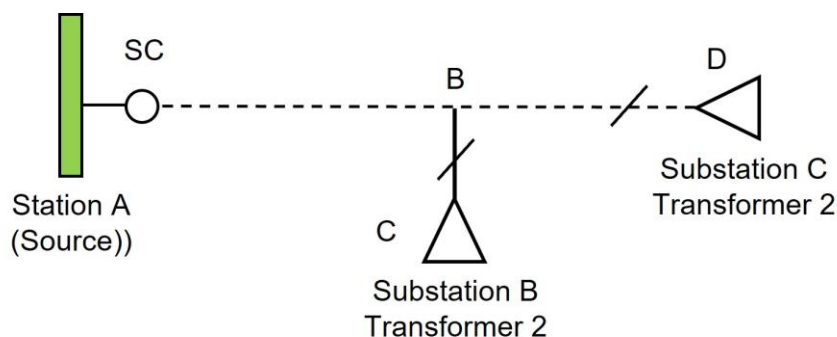
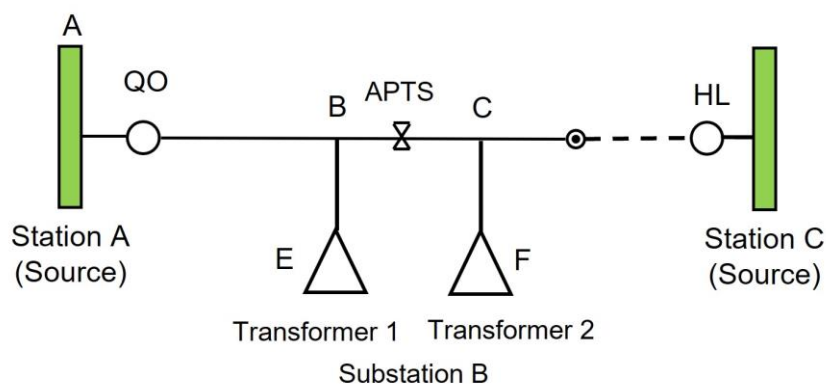


Exhibit 9.2.2 – Tie Line Diagram Example (Network)



The subtransmission system has automation built into the design by utilizing a coordinated system of automatic pole top switches (APTS) as discussed in Section 8.3.1, and line section breakers on the networked tie lines to isolate faults and maintain service to customers in single contingency failure situations. For example, a fault originating on one end of a tie line could be isolated by an APTS opening between that fault and the other

parts of the line. The majority of the tie line would remain energized, as well as the substations and distribution customers it serves, minimizing or eliminating the disruption to customers. The entire 40kV APTS population is considered for replacement as part of the APTS capital replacement program (Section 8.3.1) to address high failure rates and unavailable spare parts for early vintages.

As the subtransmission circuits can serve multiple substations in sequence or parallel configuration, an outage event on the subtransmission system can impact tens of thousands of customers, particularly in an area with limited redundancy due to compacity constraints. Furthermore, subtransmission outages typically require the deployment of costly mobile generation or portable substations (Section 8.5) to restore customers in the short term, because permanent solutions often take an extended period of time to implement. Exhibit 9.2.3 below shows key statistics of the subtransmission system.

Exhibit 9.2.3 DTEE Subtransmission Circuits

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	67
40 kV	326	2,353	466	2,819
24 kV	242	177	732	909
Total	636	2,589	1,206	3,795

As discussed earlier in Section 3, the combination of aging infrastructure, increasingly severe weather events, and loading constraints contribute to an increased frequency of failures, potential for large, sustained outages when failures do occur, and difficulties in accommodating long term localized customer load growth. The Company's subtransmission strategy is structured to improve the reliability, safety, efficiency and system capacity of the subtransmission system in both the near and long-term.

9.2.1 Subtransmission Strategy

The Company has a four-part strategy to improve the reliability performance, safety, efficiency, and capacity of the subtransmission system. These four parts are:

1. Improve reliability in the near-term through the PTMM program by bringing the subtransmission overhead circuits on-cycle within this program.
2. Increase automation on the subtransmission by completing the replacement of the 40kV APTS devices as discussed in Section 8.3.1
3. Redesign and rebuild sections of the subtransmission to updated standards to improve reliability, safety, and efficiency and increase capacity where it's currently constrained or where there is strong customer load growth, as well as increase automatic restoration and truck accessibility.
4. Decommission the 24kV system as part of a collaboration with the distribution planning teams and the 4.8kV conversion strategy.

9.2.2 Scope of Subtransmission Redesign and Rebuild Projects

Projects which redesign and rebuild the subtransmission system will dramatically improve safety, reliability, operability, and increase capacity by upgrading stations and rebuilding overhead and underground subtransmission circuits.

Station upgrades involve the installation of large transformers, capacitor banks and associated equipment that will provide additional capacity, redundancy and voltage support. Overhead subtransmission work includes replacement of aged wooden poles with new and strengthened steel poles, porcelain insulators with polymer clamp top insulators, and small diameter aging conductors with larger, stronger conductors which leads to improved safety by reducing downed wires. The current overhead subtransmission conductor standards used in replacement projects are designed to be capable of withstanding winds up to 90mph and include conductor with approximately twice the strength of existing conductors to more easily withstand impacts from trees. In addition to greater strength, the larger conductor will also provide significantly more capacity on each circuit. It will also reduce the magnitude of voltage drop over long distances on the system, which reduces grid efficiency, and can result in power quality issues for our customers.

Underground subtransmission work involves replacing or upgrading cables that are at-risk or overloaded.

Rebuilding the subtransmission system will reduce both the frequency and impact of failures. In addition to the reliability benefits, these rebuilt and redesigned areas of the subtransmission system will support area load growth for existing and new customers along with the ability to support DER interconnections. As the generation profile is expected to change with the integration of more renewables coupled with the retirement of fossil plants, improvements to the subtransmission system will support the changing power flows on the system.

9.2.3 Subtransmission Prioritization

DTEE considers six criteria when prioritizing the subtransmission redesign and rebuild projects. The first four criteria are part of what are called planning criteria violations. A planning criteria violation means that in either normal state or single contingency state, the system does not have adequate capacity to serve the existing load without exceeding equipment ratings or voltage standards. The six criteria are listed in Exhibit 9.2.3.1 below, along with definitions for each criterion.

Exhibit 9.2.3.1 Criteria to Prioritize Subtransmission Redesign and Rebuild Projects

Subtransmission Criteria	Definition
Load Loss for Single Contingency	Total load that will be shed in certain conditions when a subtransmission line can no longer support the substation and does not have a back-up
Load over Emergency Rating for Single Contingency	Load in excess of the emergency rating of a subtransmission line during a contingency event (i.e., outage)
Load over Day to Day Rating, Normal Conditions	Load in excess of the rating of a subtransmission line during normal conditions
Voltage Violation	Voltage drop on a subtransmission line exceeds standards when it is not in its normal configuration (i.e., due to an outage)
Strong Load Growth Prospect	Subtransmission lines that are predicted to experience load growth
Reliability	History of outages or equipment failures on the subtransmission circuit

The Company evaluates system loading on an annual basis and ranks the planning criteria violations based on severity (refer to Section 10.2.2 for further information on planning and forecasting tools). Projects are then identified to alleviate the constraints of the limiting elements on the system. The scope of the projects and future subtransmission system configuration is designed to accommodate expected load growth for a specific area and is influenced by distribution system plans to construct new and retire aged substations. These distribution plans provide the necessary input to ensure the scope of the subtransmission projects will meet the long-term need of customers. In addition to planning criteria violations and future distribution system plans, the Subtransmission Planning Engineering group also closely monitors the reliability of the system and identifies circuits which have had repeated reliability issues. Once these poor reliability circuits are identified, the outages are analyzed to determine the most effective project to improve reliability performance. The project plans are developed to improve reliability based on the locations of the existing lines and the areas in which outages have occurred. While these projects improve reliability, safety improvements are also made by replacing aged conductors which reduces wire down events and provides increased capacity with the larger wires.

Consistent with other strategic projects and programs, Subtransmission rebuild and redesign projects are evaluated and prioritized using the GPM. Specifically, the criteria used to prioritize subtransmission projects listed above are included in the GPM impact dimensions which are discussed in Section 12.1. Planning criteria violations and potential for strong load growth are included in the Overload Relief and Capacity Relief dimensions, while reliability improvements are factored into the SAIDI and SAIFI. Projects which provide a higher level of benefits, such as amount of load relief accomplished, per dollar invested will receive higher GPM scores and be prioritized in the investment plan. Exhibit 9.2.3.2 lists the highest ranked 25 subtransmission rebuild and redesign projects.

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Exhibit 9.2.3.2 Highest Ranked 25 Subtransmission Load Relief Project Dimensions Overview

Index	Project	Community	Load Loss for Single Contingency	Load over Allowable Emergency Rating for Single Contingency	Load over Day to Day Rating	Strong Load Growth Prospect	Voltage Violation
1	Tie 3416	Elkton, Pigeon	✓	✓	✓	✓	✓
2	Trunk 7105	Southfield	✓	✓	✓		
3	Trunk 4217	Grosse Pointe Harper Woods, Detroit	✓	✓	✓		
4	Tie 3705	Dundee			✓		✓
5	Boyne	Macomb, Harrison, Clinton, Mt. Clemens, Chesterfield, New Baltimore	✓	✓		✓	
6	Bad Axe Transformer 102 Addition	Bad Axe	✓	✓			✓
7	Hurst	Hartland	✓				✓
8	Trunk 3509	Royal Oak		✓	✓		
9	Sandusky Transformer 101 Breaker	Sandusky			✓		
10	Tie 810 Gramer	Lenox	✓	✓		✓	✓

Index	Project	Community	Load Loss for Single Contingency	Load over Allowable Emergency Rating for Single Contingency	Load over Day to Day Rating	Strong Load Growth Prospect	Voltage Violation
11	Trunk 4601	Burlington, Burnside, Marlette	✓			✓	✓
12	Trunk 4245	Eastpointe	✓				
13	Tie 7504	Novesta	✓			✓	✓
14	Derby	Vassar	✓			✓	✓
15	Tie 6907	Rochester Hills	✓			✓	
16	Pigeon Area	Unionville, Sebewing, Kilmanagh, Pigeon, Bayport, Caseville, Kinde, Port Austin	✓				✓
17	Trunk 4911	Lenox, Chesterfield, New Baltimore, Ira	✓				
18	Trunk 7386	Madison Heights, Warren	✓				
19	Trunk 3508	Troy	✓				
20	Trunk 3546	Royal Oak	✓				
21	Trunk 328	Detroit	✓				
22	Trunk 362	Detroit	✓				
23	Tie 4105	Lexington, Croswell					✓

Index	Project	Community	Load Loss for Single Contingency	Load over Allowable Emergency Rating for Single Contingency	Load over Day to Day Rating	Strong Load Growth Prospect	Voltage Violation
24	Oak Beach Capacitor	Port Austin					✓
25	Trunk 1444	Monroe					✓

9.2.4 Subtransmission Projects and Programs

The portfolio of over 60 projects listed in Appendix B includes investments focused on improving the subtransmission system and improving grid reliability and operability. Exhibit B.2.1 in the Appendix lists the local community and scope of work for the identified subtransmission redesign and rebuild projects. Exhibit B.2.2 in the Appendix lists the projected costs and timeline for the projects.

Given the current state of the subtransmission assets and their critical role in grid reliability and capacity, DTEE plans to continue to increase the investment in the subtransmission system in future years, with the pace of that growth influenced by the signposts that materialize for the scenarios discussed in the Grid Modernization Process (Section 3), specifically the Electrification and DG/DS scenarios which could cause additional circuits on the subtransmission system to violate planning criteria. Additionally, as the Company continues to evaluate the impact of potential peaker retirements on the distribution system, future subtransmission projects will be developed to mitigate those impacts.

Exhibit 9.2.4.1 shows the yearly projected investment level for the Subtransmission Redesign and Rebuild program.

Exhibit 9.2.4.1 Projected Subtransmission Redesign and Rebuild Capital Investment

	2024	2025	2026	2027	2028	Total Investment 2024-2028
Subtransmission Redesign and Rebuild Capital Investment (\$ million)	\$100	\$100	\$108	\$108	\$108	\$524

9.2.5 Impact of Peaking Generation on the Distribution System

At the end or edge of the larger grid, the electrical distribution system is dependent on a robust upstream transmission system and generation fleet to ensure consistent reliable power is available to all customers. The current electric grid, as it exists today, was designed in concert with generation resources to provide the necessary capacity and redundancy to support power

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2023 Distribution Grid Plan U-20147

delivery to customers. Generation resources can serve different functions for the electric grid based on their operating characteristics and physical location.

The generation peaker fleet plays a key role in supporting the reliability and operability of the distribution grid. Peaker generation resources have the ability to go from offline to full load within minutes to meet emergent system demand providing grid edge local capacity and voltage support during planned and unplanned outages on the distribution system. The peaker generation units are utilized during planned outages to provide local system support in the event of any system issues or unexpected power flows. This support is critical to execute the necessary shutdowns needed to perform routine maintenance and replacements on equipment while minimizing customer interruptions. The generation peaker fleet also supports necessary system upgrade projects that support the current and future needs of customers.



In some circumstances, peaker generation units also provide an ability to restore service to customers during a storm or other unplanned outage events before the grid can be fully restored to normal operating conditions. For example, peakers are utilized to mitigate equipment overloads and low voltage issues on the distribution system during events such as a storm, system equipment failure, and performing routine maintenance on the system. During routine maintenance on a transmission (120kV) line or subtransmission (40kV) line, peakers can be utilized in the event of next contingency loss of another piece of 120kV or 40kV equipment. In the case of next contingency, peakers could be put in service and used as necessary to support the system and prevent cascading outages. Without peaker support, and until distribution system mitigations can be developed and constructed, the Company's ability to serve pockets of customers during adverse system conditions may be negatively impacted.



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2023 Distribution Grid Plan U-20147

The 4.8kV and higher voltage systems are capable of accommodating electric vehicles (EVs) and DER. However, in areas where the 4.8kV system is near capacity, increased loads at the grid edge, such as adoption of EVs, can both thermally overload conductors and create significant voltage drops. Conversion to a higher voltage introduces more system capacity to handle future electrification by increasing conductor size and reducing voltage drop while also improving reliability.

A summary of the 4.8kV system as compared to the 13.2kV system is shown in the two tables below. The tables below also include statistics on the 8.3kV system which is discussed further in Section 9.3.7.

Exhibit 9.3.1.1 General Purpose Substations by Low Side kV

Substation Type	Total Number of Substations	Number of Substations by Low Side kV			
		4.8	8.3	13.2	4.8 and 13.2
General Purpose	542	244	4	243	30

Exhibit 9.3.1.2 DTEE Distribution Circuits – Line Miles by Line Voltage

Bus Voltage	Number of Circuits	Overhead Miles			Underground			Total Miles	Total Customers
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV		
13.2 kV	1,269	11,796	16	5,596	10,710	1	417	28,535	1,030,999
8.3 kV	13	0	45	0	1	18	0	63	8,202
4.8 kV	1,991	31	0	11,064	274	0	1,937	13,307	1,213,025
Total	3,273	11,828	60	16,660	10,985	18	2,354	41,905	2,252,226

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2023 Distribution Grid Plan U-20147

Witness: Kryscynski

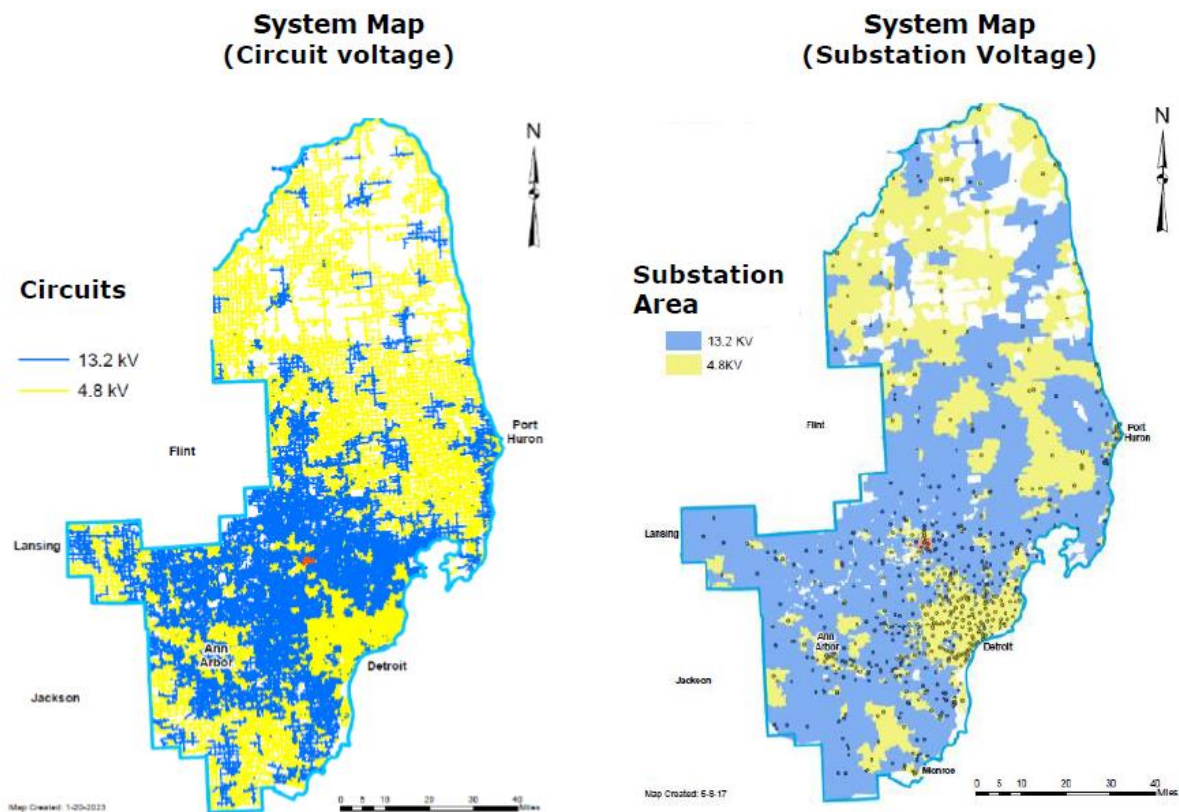
Page: 110 of 274

As the Exhibits above indicate, there are approximately 16,700 miles of overhead 4.8kV circuits on the DTEE system. Over 11,000 miles are served from a 4.8kV substation, and over 5,500 miles are served from 13.2kV substations. The 5,500 miles of 4.8kV overhead circuit served by 13.2kV substations are referred to as isolation down (ISO Down) areas and are created when step-down transformers are installed on 13.2kV circuits to lower the voltage to 4.8kV to serve the circuit downstream. In most cases the 4.8kV circuit is the original circuit infrastructure and the 13.2kV circuit and substation feeding it were rebuilt to alleviate a loading constraint.

The maps below show the 4.8kV system in yellow at both a substation/bus level and a line mile level (which includes the ISO downs). Comparing the two, significant areas on the western, southwestern and Thumb area are ISO down areas as they are yellow in the left map, and blue in the right map. Geographically, approximately 2,000 miles, or 12.5%, of the 4.8kV circuitry is located within the City of Detroit. The remaining 4.8kV is located across the entire service territory from the northern thumb region all the way to the southern territory in Monroe County.

The voltage map for DTEE's distribution system is shown in Exhibit 9.3.1.3 below.

Exhibit 9.3.1.3 DTEE Distribution Voltage Map



9.3.2 Strategies to Address the 4.8kV System

As described earlier the 4.8kV system is aged and has challenges related to reliability, capacity, and the safety of ungrounded downed wires. In the near-term, DTEE is addressing many of these challenges through the Hardening program discussed in Section 8.2, the Pole Top Maintenance and Modernization (PTMM) program discussed in Section 8.1, and Automation discussed in Section 10. In the longer-term, phasing out the 4.8kV system is an integral part of DTEE's grid modernization strategy.

The conversion and consolidation projects will bring multi-faceted benefits of safety improvements, load relief, risk reduction, reliability improvements, technology modernization and cost reduction. The conversion program offers several customer benefits:

- Relieves current load constraints and provides capacity for future load growth, including electrification load and accommodation of DER
- Provides transformational reliability and safety improvements such as an 90% reduction in customer minute interruptions, wire downs, and trouble events
- Allows for the decommissioning of aging equipment which will lead to improved reliability and lower emergent maintenance costs
- Typically converting 4.8kV substations allows for a single 13.2kV substation to serve the customers on 2 to 4 older substations. This consolidation will reduce the amount of substation equipment and system cable that needs to be maintained. Converting and consolidating 4.8kV circuits and substations also allows for the decommissioning and removal of the aged 4.8kV substation equipment, and distribution and subtransmission underground cables
- Converted areas will be rebuilt to the latest automation standards, which will enable the use of FLISR (see Section 10.2), and dramatically improve restoration times which will lower emergent costs.

9.3.3 Investments to Convert the 4.8kV System

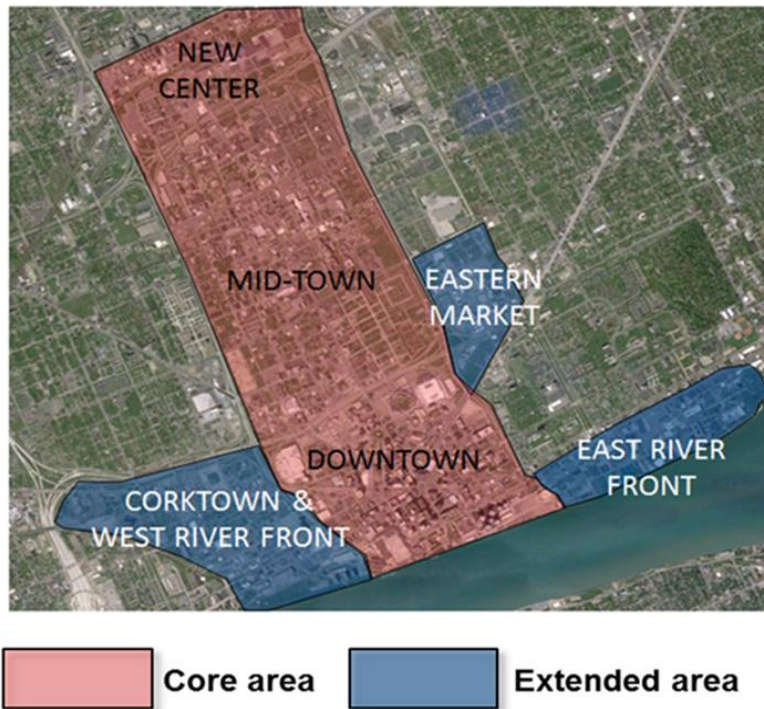
Investments to convert the 4.8kV system can be divided into three groups: City of Detroit (CODI) projects, 4.8kV conversion projects, and the 4.8kV isolation down (ISO) area conversions.

CODI is a subset of the overall 4.8kV conversion strategy targeted in the city of Detroit. Electrical system infrastructure in the city of Detroit dates back to the early 20th century and a significant portion of it is at end-of-life. A resurgence of development in the greater downtown Detroit area in recent years has resulted in increased loading on the aged, often end-of-life assets. The downtown CODI program is different from other conversion and consolidation projects due to the presence of a large amount of underground system cable and secondary network cable running under streets and through manholes, adding to the complexity of operating, maintaining, and upgrading this part of the system. The substation and circuit upgrades must be sequenced and conducted in a robust, multi-year program.

The Exhibit below shows the areas of Detroit that are being addressed by the CODI program, which includes a core area from Downtown to the Midtown and New Center areas and an extended area including Eastern Market, Corktown, and the West and East Riverfronts. There are approximately 31,800 customers served in this area including 27,486 residential, 4,299 commercial, and 15 industrial customers. The area also includes several hospitals, universities, and large sports and entertainment venues.

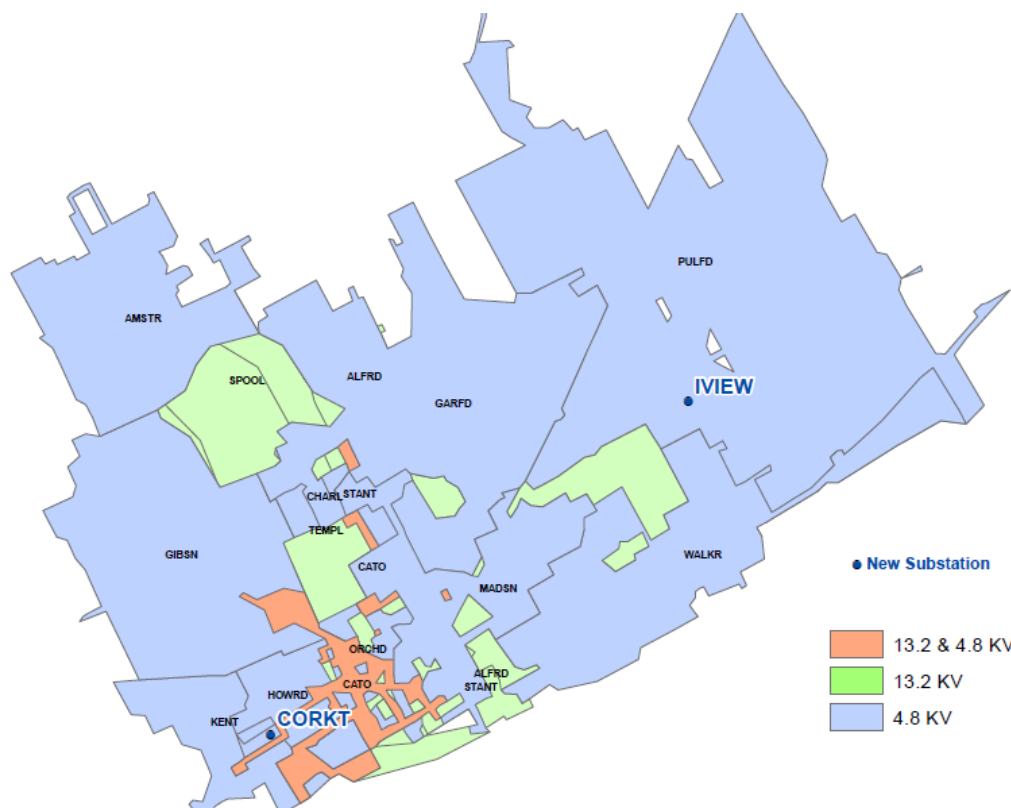
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2023 Distribution Grid Plan U-20147

Exhibit 9.3.3.1 Downtown City of Detroit Infrastructure (CODI) Scope Area



The Downtown CODI program consists of 13 projects including the targeted network secondary cable replacement program. Exhibit 9.3.3.2 illustrates the substation areas for the CODI program which is expected to be complete by the end of 2035.

Exhibit 9.3.3.2 CODI Program Substation Areas



4.8kV Conversion Projects

This category includes conversion of all 4.8kV circuits served by 4.8kV substations outside of the geographic CODI area.

The work performed as part of a 4.8kV Conversion includes:

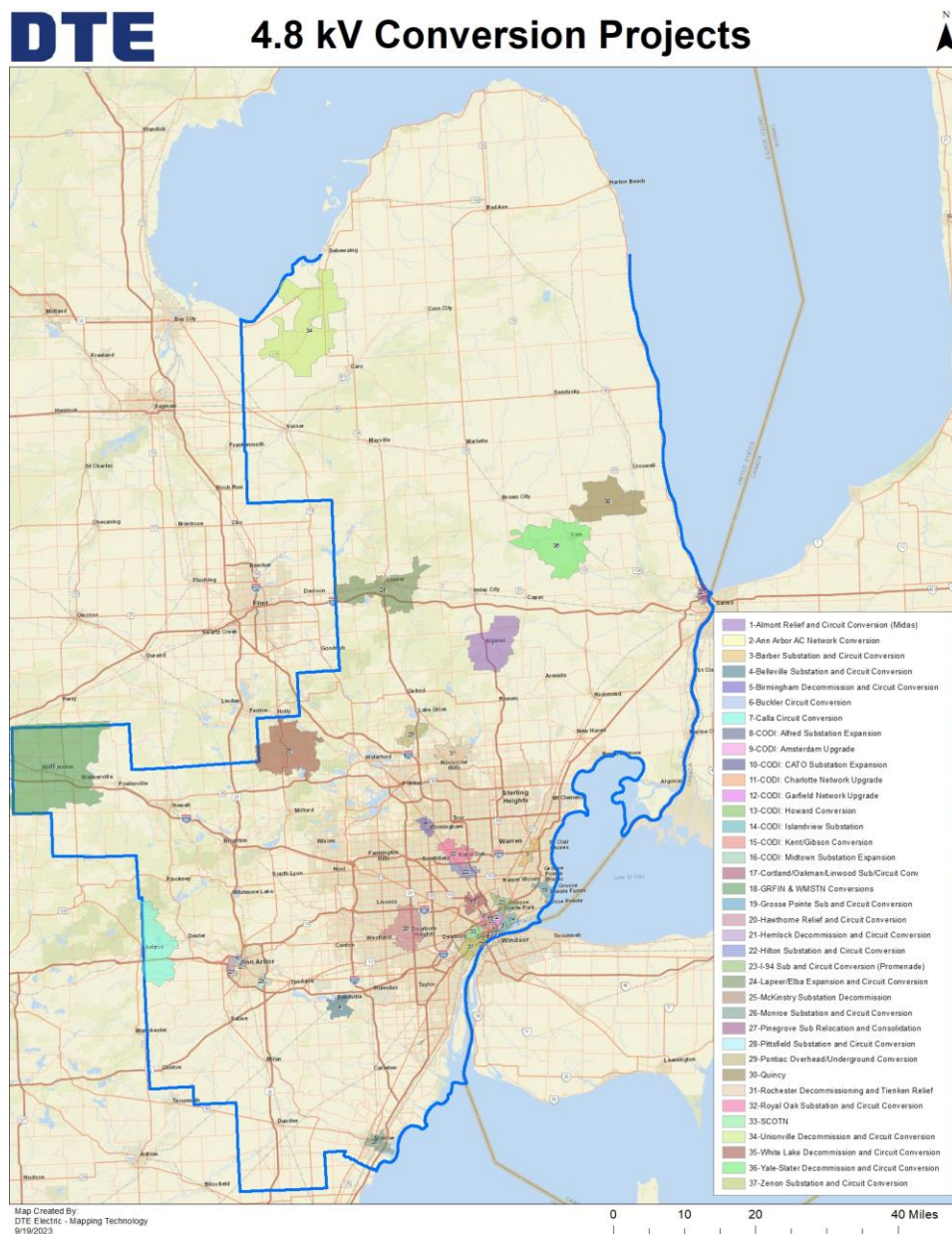
- Building new 13.2kV substations or upgrading existing 13.2kV substations to absorb 4.8kV substation load.
- Installing controls and automation in the substations and circuits to our latest design standards
- Reconfiguring circuits and establishing new jumpering points.
- Completing overhead pre-conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire.

Michigan Public Service Commission
DTE Electric Company
2023 Distribution Grid Plan U-20147

- Rebuilding underground infrastructure.
- Reconductoring overhead lines as needed based on modern standards and new circuit configurations.
- Establishing new distribution circuits from new, upgraded, or existing 13.2kV substations.
- Reconfiguring circuits and establishing new jumpering points.
- Converting and transferring the load off the 4.8kV substations to the 13.2kV substations.
- Decommissioning of aging 4.8kV substations and associated subtransmission infrastructure

Exhibit 9.3.3.3 provides a map to illustrate the locations of the 4.8 kV Conversion and Consolidation projects.

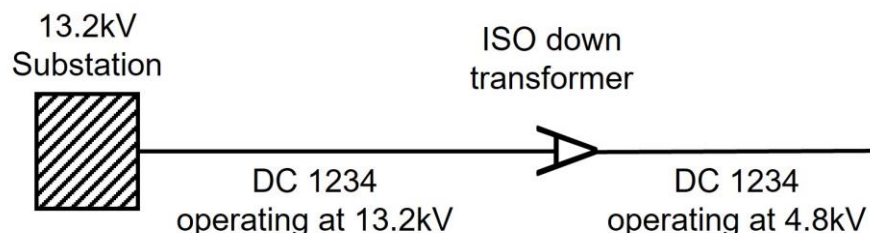
Exhibit 9.3.3.3 4.8kV Conversion Map



4.8kV ISO down area conversions

As described above, the Company operates some circuits as ISO downs, 4.8kV circuits that are fed from a 13.2kV substation. On these circuits the higher voltage is stepped down to 4.8kV by a transformer and the rest of the circuit downstream of that transformer operates in a 4.8kV delta configuration. Exhibit 9.3.3.4 illustrates a circuit with an ISO down area.

Exhibit 9.3.3.4 – ISO Down Circuit



There are ISO downs on more than 400 circuits on the system. Exhibit 9.3.3.5 below provides the number of circuits with ISO downs, the number of customers served in an ISO down area, and the number of overhead and underground miles within the ISO down areas.

Exhibit 9.3.3.5 Number of Circuits with ISO Downs and Miles of 4.8kV

	Number of Circuits	Number of Customers	Miles Overhead Wire	Miles Underground Wire
4.8kV ISO Downs	432	142,335	5,596	417

The portion of circuit operating at 4.8kV in an ISO down area has the same characteristics of 4.8kV circuits fed from a 4.8kV substation including the same reliability, capacity, safety, and operational flexibility challenges. As part of DTEE's long term vision to convert the 4.8kV system, converting the ISO down areas to a higher voltage will also be required.

The work required as part of a 4.8kV ISO down conversion includes:

- Installing controls and automation on the circuits
- Completing overhead pre-conversion work including rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire
- Rebuilding underground infrastructure as needed
- Reconductoring overhead lines as needed

- Reconfiguring circuits and establishing new jumpering points
- Removing ISO down transformers

9.3.4 Prioritization of Conversion Projects

Prioritization of near-term conversion projects

Conversion and consolidation projects provide many benefits including safety improvements, load relief, risk reductions, reliability improvements, technology modernization and cost reduction. While other investments such as PTMM (detailed in Section 8.1 and the 4.8kV Hardening program (detailed in Section 8.2) can provide many of these benefits, converting the 4.8kV system is the strategy used to address load constraints, replace the aging substation equipment and change the configuration from an ungrounded system to a grounded system.

Approximately one third of the system has some form of loading constraint on substations, circuits, or equipment (Section 9.1 discussed the impacts of operating under loading constraints). Since conversion of the 4.8kV system addresses capacity constraints and aging substation equipment, the primary factors considered when developing conversion projects are:

- Substation firm rating
- Circuit overloads
- Wire downs per overhead mile
- Substation risk ranking

Consistent with other strategic projects and programs, 4.8kV conversion projects are evaluated and prioritized using the GPM, which takes into account the factors above, in addition to reliability improvements and investment in EJ communities. While these criteria initially prioritize substations for conversion, other criteria are also considered when developing and proposing a project. For example, adjacent substations are evaluated for inclusion, the feed for the new substation is considered and property for the new or expanded substation must be available and acquired.

Prioritization criteria – ISO downs

The 4.8kV ISO down circuits are already fed from a 13.2kV substation which removes the substation firm rating and the substation risk ranking from prioritization consideration. Without the

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2023 Distribution Grid Plan U-20147

need to consider substation factors, the following become the driving factors of 4.8kV ISO down conversions:

- Safety (wire down reduction)
- Reliability (customer minute interruptions)
- Costs (avoided O&M and capital)

9.3.5 4.8kV Conversion Plan for 2024-2028

Exhibit 9.3.5.1 Projected 4.8kV Conversion Capital Investment

Project/Program (\$ millions)	2024	2025	2026	2027	2028	Total Investment 2024-2028
CODI	\$95	\$126	\$148	\$119	\$90	\$579
4.8kV Conversions	\$66	\$66	\$185	\$243	\$310	\$869
4.8kV ISO down Area Conversions	\$10	\$10	\$10	\$10	\$10	\$50

9.3.6 4.8kV Conversion Plan for 2029 and Beyond

The challenges of the 4.8kV system, including age, configuration, and loading have been described in detail in this section and in Sections 4 and 5. These challenges are likely to increase based on the impact analysis of the scenarios discussed in Section 3. As the 4.8kV system will be less and less likely to meet customer needs over the coming decades, the Company has developed an aspirational goal to convert all the lower voltage (4.8kV



and 8.3kV) circuits and substations by 2040. This effort will be significant and complex. Even after the investments outlined in this DGP there will still be nearly 16,000 overhead miles of 4.8kV distribution circuits and over 200 4.8kV substations remaining. The investment needed to completely convert the 4.8kV system to a higher voltage is estimated at \$20-25 billion in 2023 dollars, using current labor, material and productivity assumptions. Approximately \$3 to \$4 billion

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

of this investment includes conversion of the ISO down circuits which already have 13.2kV substations feeding them.

The Company has begun developing a long-term plan for conversion to outline the sequence of projects to come after the timeline of this DGP. The highest priority investments after 2028 will be investments needed to complete projects that were started in the later years of this plan. For example, as most large conversion projects require multiple years from engineering to completion of construction, projects started in 2026-2028 will continue past the 5-year timeframe in the DGP. Based on current project estimates, \$1 billion of investment is needed to complete these projects, including completing the entire scope of all CODI projects.

Looking beyond projects included in this DGP, the next set of 4.8kV substations and circuits slated for conversion will be driven by loading and load relief needs. The company has used the components of the GPM that rank load and capacity constraints on the distribution system and identified the highest ranked 25 substations based on the GPM dimensions of 'Overload Relief' and 'Capacity Constraints' which consider the six metrics listed in Exhibit 9.3.6.1 below. More information on the GPM metrics will be discussed in Section 12.1 – Investment Selection Methodology.

Exhibit 9.3.6.1 – GPM dimensions related to distribution system load relief

Overload Relief	Capacity Expansion
• Substation equipment over day-to-day • Circuit over day-to-day	• Substation over firm (today) • Substation over firm (2035) • Strong near-term load growth • Circuit over design order (DDO)

Given the potential timeframe of when these projects would be started, cost estimates and project scope should be considered preliminary. High level characteristics of the projects to address the next 25 4.8kV substations with the highest load constraints are provided in Exhibit 9.3.6.2 below. As was described in Section 9.3.2, a typical conversion project includes multiple substations based on the higher capacity of a single 13.2kV substation compared to the capacity of a 4.8kV substation. The scope of work therefore includes 24 adjacent substations to the targeted

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DTE Electric Company

2023 Distribution Grid Plan U-20147

overloaded substations in order to fully realize the benefits of the higher capacity, including reducing the amount of aging equipment on the system.

Exhibit 9.3.6.2 – Conversion Projects to Address 25 4.8kV Substations with Highest Loading Constraints

Total 4.8kV Substations	49 (25 based on loading constraints and 24 adjacent substations)
Estimated cost	\$4 billion
Overhead miles	2,400
Substation % over firm (today, average)	112%
Substations with circuit loading constraints	34
Average All-weather SAIDI	479 (4 th quartile)
% of customers in EJ communities	32%

Based on the current state of the substations above, conversion projects will provide substantial load relief, reliability and safety improvements with a significant share of the investments impacting customers in EJ communities.

Within this group of conversion projects, the GPM will be used to prioritize the sequencing of projects. It should be noted that for planning for projects starting in 2029 and beyond, prioritization and sequencing will be an iterative process. The GPM metrics include the output from the integrated forecasting tools that will enhance planning capabilities and incorporate additional data, such as propensity for adoption of EVs and DER and hourly load shapes, into the current substation loading profiles (refer to Section 10.2.2 for detailed information on planning and forecasting tools). In addition, the pace at which electrification develops will further impact which substations are subject to the most significant loading constraints.

In addition to the projects to convert circuits fed by 4.8kV substations, the Company will increase investments to convert the 4.8kV ISO areas to achieve the aspiration of converting the entire system. Based on current estimates, the Company would need to invest approximately \$320M per year from 2029-2040 to convert the approximately 5,500 ISO down miles. Circuits for ISO down conversion will be prioritized based on safety (wire downs), reliability and avoided trouble costs, as was also described in Section 9.3.4.

The total conversion of the 4.8kV system will provide a modernized grid for our customers and will provide transformational benefits of improved safety, reliability and relief of loading constraints. Designing the distribution system with sufficient capacity will increase operational flexibility, increase resiliency, and ensure that increased customer demands for the adoption of new technologies can be met by the grid.

9.3.7 Pontiac 8.3kV Conversion

DTEE did not construct the 8.3kV system that serves the City of Pontiac. Located within DTEE's service territory, it was acquired from CMS Energy in the 1980s. The 8.3kV system is served by four substations: Bartlett, Paddock, Rapid Street, and Stockwell, and their 18 distribution circuits.

Unlike the 13.2kV system, contingency options are limited for the 8.3kV system. Because the 8.3kV system is an island surrounded by the 13.2kV system, it is impossible to transfer load from 8.3kV circuits to neighboring facilities. This results in a high risk for stranded load in the event of an 8.3kV substation outage event.

Adding to the operational challenges, replacement parts are no longer available for 8.3kV breakers and other substation equipment due to their obsolescence. Non-standard clearances require substation shutdowns for operations and maintenance. This leads to extended customer interruptions during outage events and leaves the system in an abnormal state for extended periods of time if any 8.3kV equipment fails. In addition, crews must be trained to operate and maintain the 8.3kV system, adding to training and operation and maintenance costs.

Meanwhile, the City of Pontiac has gradually increased in load in the past 7 years.

The plan to address the 8.3kV system has been developed, starting with the upgrading of the system vaults. The original underground vaults were a safety hazard, with live front equipment and often insufficient arc flash distances. This work will be completed in 2023. The circuit conversion work involves conversion and transfer to circuits out of Catalina substation with the remainder to be converted and transferred to circuits out of a new substation adjacent to the existing Wheeler substation site. For the conversions to take place, services in Pontiac fed through 8.3kV rated underground equipment will need to be upgraded. This effort will require replacement of customer-owned switchgear, fuses, transformers, and cables rated at less than 15kV class.

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2023 Distribution Grid Plan U-20147

As a result of the project, all four 8.3kV substations, Bartlett, Rapid Street, Paddock and Stockwell will be decommissioned by 2029. In addition, the Wheeler substation upgrade will enable load to be transferred off Bloomfield Substation. This will allow Bloomfield Substation to be decommissioned, thus taking its at-risk switchgear out of service. Exhibit 9.3.7.1 provides a summary of the project capital investment for the next 5 years.

Exhibit 9.3.7.1 Pontiac 8.3 kV Conversion Capital Investment

Project (\$ millions)	2024	2025	2026	2027	2028	2024- 2028 Total
Pontiac 8.3 kV Conversion	\$19	\$31	\$29	\$18	\$18	\$114

9.4 Undergrounding

Background

As discussed in Section 3.1.2, DTEE is planning for a future that will likely include an increase in storm frequency and severity. In the face of the resulting outages, customers and other stakeholders have increasingly asked, “why not put the lines underground?” As noted in Section 14.1 on customer engagement, recent customer research of over 4,000 customers indicated a specific interest in improving reliability by burying lines underground. Since the 1970s, new construction of subdivisions and other projects (as possible) have required installation of underground lines, resulting in well over 30% of the current DTEE system running underground. In recent years, DTEE has been developing small pilot projects to move existing overhead infrastructure underground. As the company works towards undergrounding as a viable and economic option to overhead construction, it will be worked into the strategy for circuit conversions. The company is committed to continuing to mature its capability in Undergrounding the overhead infrastructure and lower the cost so that significant portions of our system can be relocated underground.

Undergrounding will be implemented in a manner that balances reliability and other longer-term benefits of underground infrastructure with the initial cost of installation. The Company has recently completed one project, Appoline, and additional projects are being developed. The

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2023 Distribution Grid Plan U-20147

Company is planning to develop projects with varying scopes to test different construction and outreach methodologies. This includes partnering with the DTE Gas Company to find synergies in areas of joint underground construction, executing both urban and rural undergrounding to determine benefit and cost differences, and working with customers to determine the most effective outreach strategy. Additional completed projects will help identify pathways to reducing project costs, while also providing more data points for use in evaluating overall total cost over time of underground infrastructure vs. similarly situated overhead assets. The projects will incorporate benchmarking of other utility underground construction practices, develop solutions for complexities including obtaining customer agreements, develop cost-saving practices, and complete a comprehensive long-term or life cycle cost analysis of underground vs overhead infrastructure. When supported by the expected results of the projects, undergrounding as a project option would be applied to areas based on several factors including recent reliability, downed wires, and maintenance costs. Due to the forecasted costs for undergrounding subtransmission and distribution backbone lines, the company is not currently pursuing a program to address these lines but instead evaluating the undergrounding of single-phase lateral infrastructure and services primarily serving residential customers. As pilots are developed, the Company will present them to the Commission, as requested in Order U-20836, with analysis of the “benefit/cost of the proposed undergrounding pilot compares to that of other solutions the company is currently employing to enhance the reliability of the distribution system”.

The Company has a unique opportunity to align the Undergrounding program with the 4.8kV conversion program, where significant overhead rebuild would otherwise be occurring. When evaluating the economics of undergrounding a target area, cost used in analysis would be the incremental cost to underground versus the cost to rebuild the overhead. The analysis will also include consideration of life cycle cost of overhead vs underground construction, including potentially reduced costs for underground construction maintenance over time, including eliminating the tree trim costs for overhead as an example. It is anticipated that when considering the lifecycle cost of undergrounding, these assets will offer opportunities to cost effectively underground a significant portion of rear-lot overhead laterals and services when converting circuits.

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2023 Distribution Grid Plan U-20147
Appoline Pilot

History and Status

DTEE began an undergrounding project in 2018 on the Appoline DC 1346 circuit. The intent of this project was to move rear-lot overhead infrastructure to rear-lot Underground Residential Distribution (URD). The goals of this project were to determine actual installation costs, understand customer acceptance, and determine opportunities to improve cost and construction efficiency in subsequent pilots. This project includes approximately 61 residential customers on two city blocks in Detroit. The scope of the project includes the installation of a looped URD system with approximately 1,300 feet of primary conductor, six transformers, and underground services to residences. When the underground equipment is completed and functional, the overhead infrastructure will be removed.

At the time of this filing, 47 of the 61 customers have already transferred to the URD Loop. Transfer of the remaining customers should be completed by the end of October 2023 with retirement of the electrical equipment on the rear-lot poles being completed by the end of November 2023.

Appoline Pilot Lessons Learned

From the Appoline pilot, the Company gained valuable experience in undergrounding existing overhead infrastructure and recorded two key learnings: rear-lot URD poses significant challenges, and early customer engagement and agreements prior to construction are critical to the success of the project. Before installation work could begin, the overhead infrastructure located in rear alleyways required extensive vegetation and debris removal. The cost and time required for these activities will be considered when developing any future rear-lot undergrounding projects. Another significant challenge impacting the schedule of this project was difficulty in contacting the homeowners, often landlords instead of resident homeowners, to obtain the approvals required to modify the electric service attachments to their homes. After limited success using several mailings and door hangers, the Company has continued using door-to-door customer outreach, which has shown improved results. Nonetheless, reaching all property owners has been a challenge that requires addressing in future undergrounding projects.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

As the Appoline pilot comes to a full conclusion, the Company will produce the requested report from U-20836 regarding the benefit/cost analysis (BCA), alternatives evaluated, and its plans for incorporating Undergrounding further into the distribution grid plan.

Benchmarking

The Company participated in a benchmarking exercise on Undergrounding with over ten peer utilities to determine the optimum infrastructure configuration and construction methods that balance reliability, cost, constructability and customer engagement when relocating infrastructure. The results overwhelmingly concluded that front-lot URD is the best option over other locating the URD in the rear. Front-lot URD provides the best customer experience for both reliability and aesthetics. Additionally, DTEE's benchmarking found that the peer utilities will complete easement acquisition and gain any necessary customer agreements prior to executing such a project. Significant cost savings were realized by Utilities that executed their Undergrounding program at high volumes and scale, having benefitted from economies of scale and productivity. The peer utilities assess target projects by evaluating the NPV over the life cycle of the asset, reliability benefit economics, and construction costs.

Another area of benchmarking explored the reasons why peer utilities are executing their Undergrounding programs. The Company found that the rationale for peer programs varied across the country, but almost all focus exclusively on single phase lateral overhead due to higher costs of undergrounding three phase and backbone with higher voltages. These higher costs are driven by higher building construction specifications, including cement reinforced duct banks.

Key lessons learned from benchmarking efforts on how to improve efficiency of execution include the importance of streamlined contracting for design, customer outreach, construction, and utilizing public right-of-way. The greatest challenge identified by other utilities for other configuration options was community acceptance once the project was already underway. To further develop the Company's experience in Undergrounding, DTEE is incorporating peer utility best practices for improving the cost efficiency of the work that may be applied more broadly across system and infrastructure improvement plans.

The benefit of Undergrounding is primarily the avoidance of outages in the impacted area caused by trees, wind, and public contact. However, customers are still vulnerable to outages from

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

damage that occurs upstream from the undergrounded portion of their circuit or substation. In large storm situations, there is an additional restoration time benefit to the entire customer population as resources will not be required to address downed wire and outage jobs on undergrounded infrastructure.

Next Steps

The Company is developing and plans to execute additional projects to gain information on expected costs and construction efficiencies. These projects will involve a mix of geography (suburban, rural) and will incorporate lessons learned from benchmarking peer utilities to develop a more cost competitive Undergrounding program. Additionally, the Company is refining its Total Cost of Ownership (TCO) model for these projects and will incorporate Undergrounding into the 4.8kV Conversion program as an option for rebuilding overhead infrastructure. Another area the Company will explore is identifying segments of high Tree Trimming and other maintenance cost segments of overhead infrastructure that would be good candidates for undergrounding.

Davison/Buffalo Charles Project

The Company plans to use the lessons learned from the Appoline project and Benchmarking to implement a new project in the City of Detroit. The scope of this project will be to replace roughly 3 miles of overhead infrastructure with underground infrastructure in the area of E. McNichols and E. Davison (Davison and Buffalo Charles neighborhoods). This area was chosen in partnership with the City of Detroit and DTE Gas. In addition to the area being a focus for some of the City of Detroit's near-term revitalization plans, there are also cost and execution benefits for implementing Undergrounding in this area. First, DTE Gas is performing gas main replacement in the area, and cost and other construction synergies are expected from collaboration between the two utilities, both of which will be using directional boring to complete their work. The combination work will also minimize the time for construction disturbance for customers, when compared to coming in before or after gas main renewal has occurred. Additionally, this area has considerable Detroit Land Bank Authority and City-owned properties where the City/Land Bank has agreed to allow easements for transformer placement.

For this project, the Company expects to remove approximately 160 poles, 2.8 miles of overhead conductor, 51 overhead transformers, 3.5 miles of secondary, and 0.7 miles of PLD primary. This infrastructure will be replaced with 4.3 miles of underground primary cable, 3.3 miles of

underground secondary cable, 9.5 miles of underground service cable, 60 underground transformers, 147 handholes, 459 junction boxes on houses, and 11.7 miles of conduit. Junction boxes are utilized so that customers are not required to relocate their interior electric wiring in order to receive the new underground service, previously fed from above their home. The area also has a lower customer density than previously completed or proposed projects, which is expected to further reduce costs.

At the time of this filing, construction is scheduled to begin in October 2023 and will continue throughout 2024.

10 Pillar: Technology & Automation



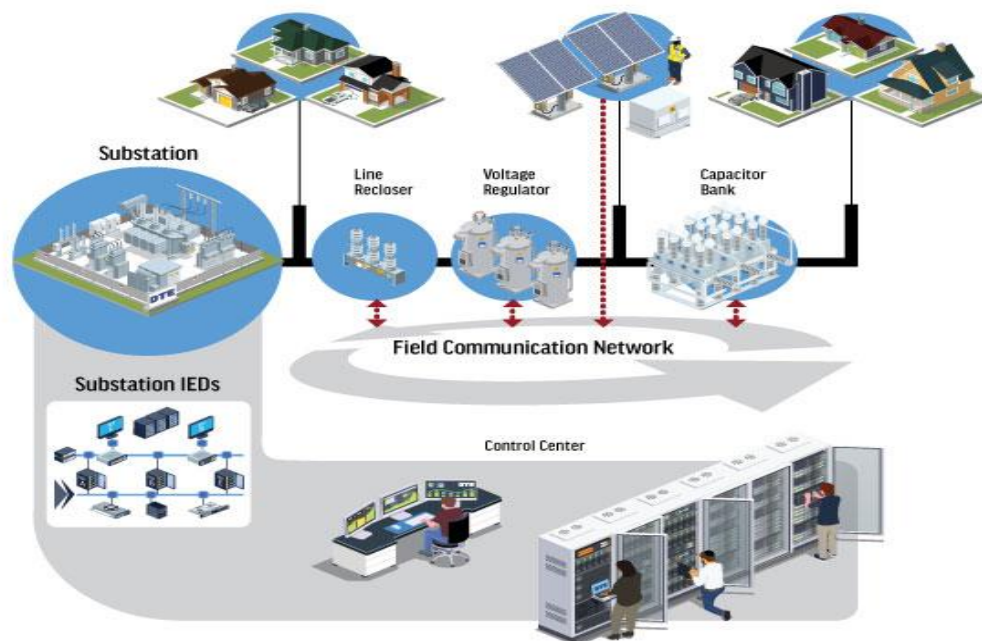
New technology is improving the way modern electric grids operate, resulting in improved reliability, performance, and safety. This technology also provides new opportunities to improve operations in ways that benefit customers, such as the ability to automatically isolate outages to limit the number of impacted customers and to provide real-time visibility into circuit and substation loading needed to accommodate increasing numbers of DG/DS and EVs (described in Section 3 above). Implementing new information technology (IT) and operational technology (OT) will streamline and optimize the Company's planning while also improving safety and productivity. These investments form the core of this investment pillar.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

A modern distribution system overview, shown in Exhibit 10.0.1 below, shows key distribution automation tools such as line reclosers,³⁸ voltage regulators,³⁹ capacitor banks,⁴⁰ substation intelligent electronic devices (IED).⁴¹ These systems and tools support the Electric System Control Center (ESOC),⁴² providing the data input to grid management tools such as the Advanced Distribution Management System (ADMS)⁴³ that are essential to modern operations.

Exhibit 10.0.1: Modern Distribution Overview

³⁸ Reclosers are devices on the distribution grid that automatically detect and interrupt transient faults.

³⁹ Voltage regulators are devices on the distribution grid that regulate and maintain voltage within a set standard.

⁴⁰ Capacitor banks are electrical devices on the distribution grid that store large electrical energy charges and are used for conditioning the flow of energy.

⁴¹ Intelligent electronic devices (IED) are devices that integrate multi-processors with the capability to receive or send data or control from or to an external source.

⁴² ESOC is the most critical facility in Distribution Operations. Personnel in the ESOC operate the Company's subtransmission and distribution system in southeast Michigan, and support generation operations. With state-of-the-art technology like ADMS and an electronic display board of the transmission, subtransmission and distribution networks, these personnel monitor alarms and system conditions, and direct field personnel to operate electrical equipment for routine switching needed for outage restoration, maintenance, and other planned activities.

⁴³ ADMS is an advanced operating technology platform that is essential to the Company's grid modernization efforts to improve system reliability and operational efficiency. It is comprised of five components that will substantially improve DTE Electric's ability to manage the flow of electricity from the point of generation to the point of delivery, to monitor the condition of the grid, to safely operate it, and to respond to emergency conditions and outages more quickly.

The Company is well positioned to utilize modern distribution system technology, including automation, because of foundational investments in DTEE's world-class ESOC, Alternative System Operations Center (ASOC),⁴⁴ and the ADMS. These three investments provide the necessary foundation for the Company to develop, deploy, and control a broad range of new technologies to improve reliability for customers by reducing the number of sustained outages and shortening others, as well as supporting the changes that are coming as part of grid modernization.

Supporting a focus on improving storm restoration efficiency, the 2023 distribution grid plan for the Technology and Automation pillar includes an acceleration of investments in distribution automation. Distribution automation describes a group of field assets such as reclosers, switches, capacitors, and sensors capable of monitoring and controlling the distribution system and supporting grid edge technologies like DER and NWA applications. Distribution automation helps customers in three important ways. First, when an outage occurs (from a tree, animal intrusion, public interference, etc.), automation can reduce the overall number of customers affected by "sectionalizing" the event to a smaller area. Second, devices used for automation can report back information to the Company's ESOC that allows the grid management system to determine the location of the equipment failure down to a few feet, significantly reducing the patrol time required by DTEE's field crews and shortening duration of the outage. And third, while crews are in route to the outage, the Company's system operators can remotely control automation devices in the field from the control center, routing power from other areas further reducing the customers affected and shortening restoration time. On circuits where this technology is installed, DTEE can reduce the number of customers affected by an outage and reduce restoration time. Estimated outage minute reductions of roughly 50% are expected when connections to other circuits allow automated reconfiguration, and 25% when reconfiguration is not practical due to system design constraints. These reductions assume existing circuit automation is not present on a circuit and that there are not any other factors limiting automated restoration such as multiple damage locations, damage on adjacent circuits or loading constraints preventing transfer.

⁴⁴ASOC, the new backup SOC (System Operation Center), will have the appropriate square footage required to co-locate necessary personnel, and will have the appropriate mechanical and electrical system redundancies as the ESOC. In addition, the new ASOC will also be outfitted with the same ADMS technology (including a video wall) as the new ESOC, for seamless operations during the transition between facilities.

In addition to investments in grid automation, DTEE's Operational technology roadmap outlines ongoing IT and OT investments in five investment areas. The roadmap focuses on technology tools within the Technology & Automation pillar. Investments within the roadmap support grid management, distribution plan, work management and scheduling, asset management, and mobile technology. These investments focus on establishing new capabilities and enhancing existing capabilities that will improve safety, reliability, and affordability for customers. Categories of investment within the Technology & Automation pillar are summarized below:

Technology and Automation Investments

Grid Automation

Grid Automation is focused on the physical infrastructure needed to support a modern distribution grid. Investments in reclosers to improve safety and reliability, capacitors and voltage regulation for CVR/VVO, as well as infrastructure to support NWA, EVs, and grid telecommunications. This section also includes initial investments in updating the AMI systems.

Operational Technology roadmap

- **Grid management**

Grid management includes Operational Technology investments that enable the Company to monitor, control and optimize the operation of grid automation investments. These projects include the full suite of ADMS distribution management applications, including outage response, fault location and service restoration (FLISR), and advanced control toolsets. and will enable distribution operators to model the real time state of the electrical system and manage the distribution network, monitor and control the power system, manage planned and unplanned outages, and analyze and optimize the quality and reliability of the network. These investments also include the platforms that enable the management of DER such as the DERMS (Distributed Energy Resource Management System).

- **Distribution planning**

Distribution planning encompasses all technology dimensions needed for distribution planning, design, specification, modeling, forecasting and the analytics of associated

data. This area accounts for systems and engineering tools needed to perform modelling functions accurately and effectively for distribution planning activities and investments. These investments also support streamlining the customer interconnections process and include investments in hosting capacity mapping.

- **Work management and scheduling**

A work management system is technology that provides a set of management tools that are used to manage labor, materials, and scheduling in the completion of work. The work management system manages both planned and unplanned work, includes work order creation, resource scheduling, and work execution for DTEE employees, vendors, and third-party crews. The system encompasses job planning, labor, material, tools, and services for both larger, complex work efforts and smaller, short-term jobs. Upon completion, work is audited and verified in the system to reconcile time capture and payment.

- **Asset management**

Asset Management systems allow the Company to manage assets to minimize the total cost of ownership while maintaining high equipment service levels. The systems include managing operational data about assets and as well as the appropriate algorithms to process that data to determine if maintenance or replacement needs to be initiated. These technologies help manage the full lifecycle of an asset, including engineering, maintenance, and financial management. DO's primary asset management systems are IBM Maximo (with industry solutions) and ESRI ArcGIS.

- **Mobile technology**

Mobility technology allows for field teams collecting and distributing data at the point of activity through mobile devices. Mobile investments include both purchase of required devices and new and existing applications that are engineered for mobile access and usage. Types of applications that rely on mobile communication include work dispatch, work execution, forms digitization, location tracking, route navigation, field analytics and secure file sharing.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Technology and Automation is a wide-ranging environment. The use of the DOE DSPx (Department of Energy Next Generation Distribution System Platform) framework,⁴⁵ discussed in Section 5, facilitates a broad understanding of the critical automation and technology components of the future grid and how they integrate.

DTEE is ramping up the deployment of technology and automation investments throughout 2023. As devices are installed, customers served by those circuits will see immediate benefits; complete deployment is expected to take five to six years. The following sections detail the Company's plan to deploy these new technologies and demonstrate how it will improve electric service and reliability for DTEE's 2.3 million electric customers. Throughout this section larger programs and projects will be highlighted and associated with gaps they close within the larger framework.

10.1 Grid Automation

Automation devices provide situational awareness about faults and other distribution system issues and help quickly identify and isolate the problem. Increasing the number of automated devices will provide improved detection of down wires and abnormal system conditions so issues can be automatically or remotely isolated, improving safety. Automated devices provide reliability benefits through targeted isolation of outages which reduce the number of customers initially impacted as well as reduce the duration of outages for those impacted by allowing automated or remote partial restoration through switching operations. Automated devices, paired with SCADA, provide the Company real-time data on voltage, current, fault analysis, and other data points and deliver the data to the ADMS. This provides control room operators and dispatchers with real-time system information and conditions. Increased situational awareness also helps crews locate outages and restore the system more quickly.

The long-term use of automation calls for the deployment of SCADA, automated field devices, and fault analysis tools. The DSPx model calls out substation and distribution SCADA and makes note of protective and switching devices, such as reclosers and voltage control devices such as capacitor banks. Consistent with this, DTEE has established standards that newly constructed and rebuilt portions of the distribution systems have SCADA enabled substation breakers, three phase reclosers⁴⁶ and capacitor controls. New circuits will also be constructed with SCADA

⁴⁵ PNNL: Grid Architecture - Modern Distribution Grid Project, <https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx>, retrieved on (09/01/2023).

⁴⁶ For circuits serving more than 400 customers.

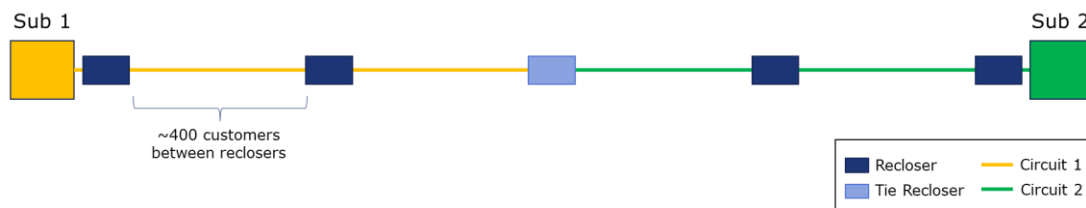
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DTE Electric Company

2023 Distribution Grid Plan U-20147

enabled tie points between circuits allowing for automated or remote restoration of undamaged sections. Standards also require the use of digital relays and communications protocols in alignment with advanced protection requirements. These standards ensure that investments made through system loading and conversion programs are consistent with enabling a modern electrical grid. As Fault Location, Isolation and Service Restoration (FLISR) advances, additional devices (e.g., reclosers, sensors, etc.) will be deployed in the field to close the gaps in grid sensing and control.

Exhibit 10.1.1: Automation Program – Retrofit Circuit Example



To achieve the benefits of automation more rapidly, the Company plans to retrofit the existing infrastructure. Retrofitting automation will be considerably faster than waiting to apply new standards to rebuild projects. This work will require bringing the existing distribution system to the retrofit specification shown in Exhibit 10.1.1. The retrofit effort will require the installation of over 10,000 distribution line reclosers as well as upgrading many switching and tie points to facilitate the ability to quickly restore customers before repairs are completed. This program will be focused on installation and automation of most of the existing 4.8kV and 13.2kV system to the retrofit specification, installing ground detection on the 4.8kV system that is retrofitted, and building switching points to enable restoration from multiple sources using automation. The tables below (Exhibit 10.1.2 and Exhibit 10.1.3) summarize the key investments and projected timelines for the grid automation section.

Exhibit 10.1.2: Key Investment Highlights for Grid Automation

Key Investment	Use Case	Implementation Highlight	DSPx Objective
Grid Automation	Establish SCADA control, automation and ground identification and isolation	Reduce sustained circuit outages, minimize the size of outages, reduce crew patrol time and operating time to speed restoration, minimize impacts of system grounds	Physical Grid Infrastructure, Sensing & Measurement, Automated Field Devices, SCADA
Grid Telecommunications program	Install fiber backbone communications to substations and advanced wireless mesh	Increased communication bandwidth and resiliency to support new grid automation devices, DER, field workers, advanced metering, including analysis and optimization of data, leading to better overall utility coordination for day-to-day operations and during storm	Operational Communications
CVR/VVO	Conservation Voltage Reduction and Volt Var Optimization. Install new SCADA enabled capacitors and replace existing capacitor controls to coordinate with substation voltage regulators to reduce system voltage and fluctuations	Reduce system losses, increase system efficiency and improve system voltage and power quality	Physical Grid Infrastructure, Sensing & Measurement, Automated Field Devices, SCADA, Volt-Var Management
Capacitor Placement and Control Program	Optimizing location of capacitors on circuits and replacing end of life controls	Improve system efficiency and voltage	Physical Grid Infrastructure that Improves sensing and measurement of reactive power through automated field devices that can be controlled by volt-var management
NWA Projects	Non-Wire Alternative demonstrations for energy storage, energy efficiency, demand	Enable more DER integration and create methods for future programs and NWA integration	Customer DER programs, DER Management, Advanced Protection,

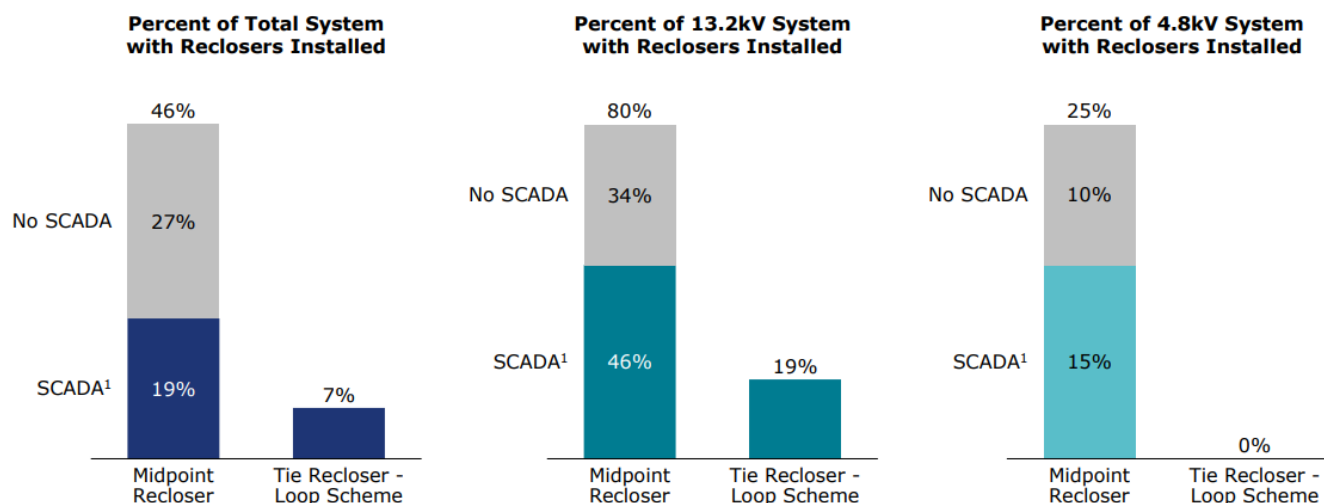
	response and integration of DER and microgrids		Physical Grid Infrastructure
Grid Edge Enablement Program	Interconnection gateways, DER controls coordination and microgrid controls, DER testing and training facility	Consistent and optimized controls and communications to streamline DER interconnection integration. Test new DER capabilities and their grid interaction prior to wide-scale deployment while also serving as a training platform	Support safe and reliable transition to clean, distributed energy resources, enables Customer DER programs, DER Management, Operational Communications, cybersecurity and Advanced Protection
Vehicle Electrification Projects	EV managed charging, Vehicle to Grid, Charger integration with other DER and grid controls	Streamline EV charging installations, Enable new capabilities for electrification and grid management.	DER Management, Vehicle to Grid and Electrification
URD Fault Indicators	Facilitate URD restoration and minimize time field crews would need to troubleshoot outage	Reduce crew patrol time, and provide faster restoration time	Physical Infrastructure, Sensing & Measurement
New Technology Evaluation Program	Assess new grid assets and technology for use on the DTEE system. Test and approve compatible equipment and develop work practices and procedures	Incorporate emerging technology into grid automation and construction to improve efficiency and reliability	Evaluate and test new Automated Field Devices and Physical Grid Infrastructure and develop standards and work practices

Exhibit 10.1.3: Key Investment and Timeline for Grid Automation

Key Investment (in millions)	2024	2025	2026	2027	2028
Grid Automation	\$61.6	\$162.6	\$190.6	\$308.6	\$469
Grid Automation Telecommunications Program	\$16.9	\$15.0	\$13.8	\$12.5	\$11.0
CVR/VVO Program	\$5.0	\$5.0	\$5.0	\$5.0	\$5.0
Capacitor Placement and Control Program	-	\$5.6	-	-	-
NWA Projects	\$14.5	\$1.3	\$0.3	-	-

Grid Edge Enablement Program	\$5.5	\$4.2	\$4.2	\$3.0	\$2.8
Vehicle Electrification Projects	\$2.9	\$1.0	\$0.8	\$0.8	\$0.5
URD Fault Indicators	\$3	\$3	\$3	\$3	\$3
New Technology Evaluation Program	\$1.2	\$1.0	\$1.0	\$1.0	\$1.0
Line Sensors	\$0.5	-	-	-	-
Large/Medium Sized DER Monitoring and Control	\$0.3	\$0.3	\$0.3	\$0.3	\$0.3
Total	\$111.4	\$199	\$219	\$334.2	\$492.6

Exhibit 10.1.4: Percent of Reclosers Installed on DTEE's System



10.1.1 Grid Automation Program

Grid Automation on 13.2kV circuits has multiple objectives including: 100% SCADA monitoring and control of overhead distribution circuits, SCADA control of existing circuit reclosers, the addition of new automation reclosers to reduce the potential impact of outages and SCADA control of existing circuit tie points. The program has a goal of reviewing and updating all 1264 circuits using reclosers and other automation devices. The reliability impact of this distribution

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

automation work is expected to be significant. As an example, a 2016 DOE study⁴⁷ showing reductions in customer minutes interrupted 17- 55% when compared to the same circuit before automation, with DTEE expecting results in the range of 25-50% depending on the conditions found at each circuit.

Grid Automation on 4.8kV circuits is very similar to the 13.2kV with the inclusion of an additional objective to establish ground detection and isolation. The 4.8kV cannot identify or isolate energized down wire as reliably as the grounded 13.2kV system, resulting in wire downs that can remain energized and pose a hazard to the public. To address this consideration, all 4.8kV circuits not identified for conversion within the next five years will get an automation device installed near the start of the overhead portion of the circuit that is able to identify and isolate down wires. This program is expected to update 1,945 circuits over the 2024-2028 period. While the safety benefits of the program are substantial, the reliability benefits would be slightly reduced when compared to the 13.2kV automation program as new outage events would be introduced when isolating down wire that currently are only interrupted during repairs.

The Grid Automation program also includes building new line extensions, replacing small wire, and adding or replacing voltage control equipment to enable new circuit connection points and bidirectional flow to be established. The circuit connection portion of the program addresses the gap that approximately 40% of existing circuits do not have connections with adjacent circuits that would allow the Company to transfer and restore customers during trouble. This program would also install SCADA enabled devices at the tie point between circuits to allow automatic or remote execution of switching to restore customers. This program would continue past 2028 with a focus on looking at circuits that need additional work to establish and automated switching points.

The overall Grid Automation program is expected to continuously increase throughout the 2024-2028 period as capacity to deploy devices increases with the program investing more than \$1 billion over the 5-year period. The program is key to achieving the long term SAIDI reduction objectives and captures many of key core components highlighted in the DSPx model.

⁴⁷ [Distribution Automation: Results from the Smart Grid Investment Grant Program \(energy.gov \)](https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf), https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf, retrieved on (09/01/2023).

Grid Automation Telecommunications Program

In addition to the automation devices themselves, a modern electrical distribution system demands a secure, highly reliable communications network that connects those devices, relaying information between the field and ESOC. Grid Telecommunications covers the operational communications portion of the physical core components within the DSPx framework. As installation of automation and other field devices continue to increase, investment to expand the company's fiber and mesh networks⁴⁸ is necessary to ensure secure and reliable communication with company data centers, substations, distribution network, automation devices and metering infrastructure as well as emerging DER installations. The current and planned network technology landscapes are shown below (Exhibit 10.1.1.1 and Exhibit 10.1.1.2) and highlight the connections and communications paths between these key components.

⁴⁸ A mesh network allows a network to have multiple pathways between network nodes that adjust automatically to conditions to allow for efficient and resilient routing of data to and from devices.

Exhibit 10.1.5.1: DTEE Current Network Technology Landscape

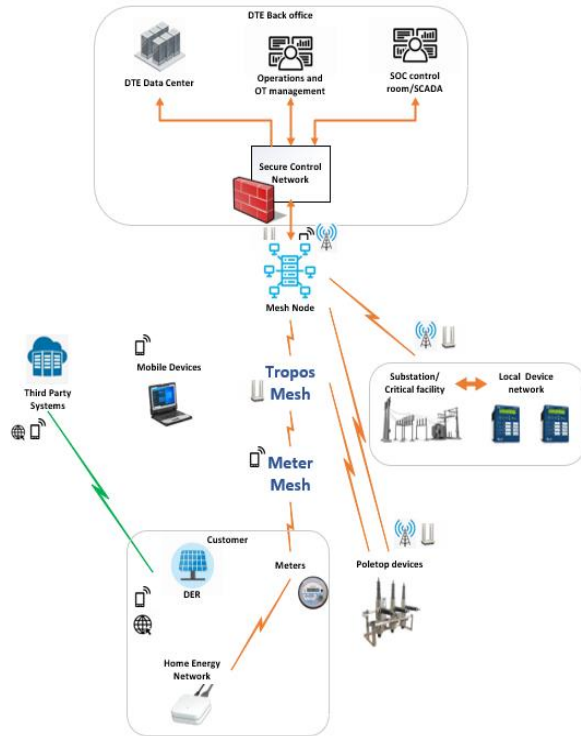
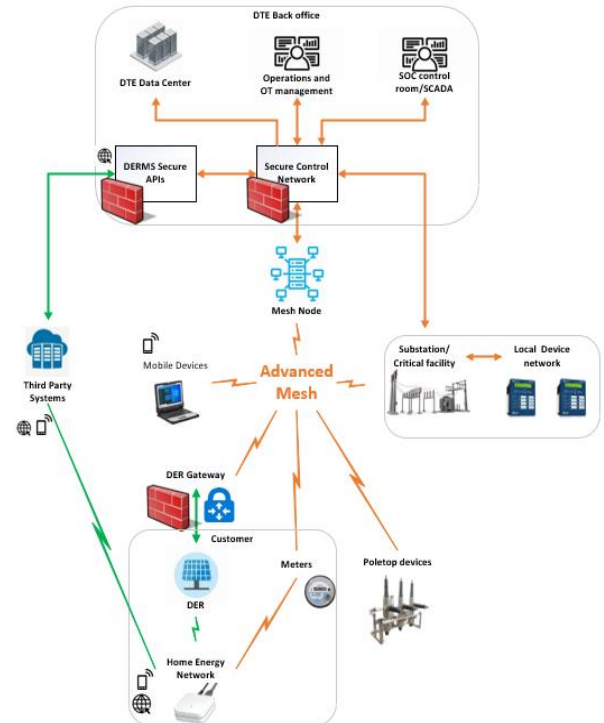


Exhibit 10.1.5.2: DTEE Future Network Technology Landscape



To date, more than 250 miles of new Company-owned fiber has been installed with a focus on connecting critical facilities such as data centers, service centers, power plants, substations, and other grid assets including metering communications towers. Many of the remaining routes will be coordinated with 40kV rebuilds to provide construction synergies and follow new truck accessible right of way. The program is also coordinated with the conversion and consolidation plan and automation plan to provide appropriate backhaul solutions to areas and minimize rework due to changing circuit configurations. Substantial completion of fiber installation is expected by 2028.

Between 2024 and 2028 fiber routers will be installed to complete fiber loops and provide communications to end points. This work will include installing communication poles, fiber entrances and taps along installed routes to make final connections into substations and support

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

the advanced mesh network deployment with additional mesh nodes. The diagram also shows how other investments such as the DER gateway incorporate customer information into the communications network.

Asset tracking tools that provide updated information on the status of the communications network and troubleshooting will be enhanced as the fiber system is brought online. Visualization and analysis tools will be implemented to allow planning and operations to view the status and location of communication assets in real time. This includes integration of telecom monitoring software telemetry and the mapping system to provide real time visualization of network status and performance. Later investments will focus on supporting the advanced mesh network including anticipated licensing costs for dedicated frequencies.

CVR/VVO Program (Conservation Voltage Reduction / Volt-Var Optimization)

CVR/VVO was piloted in 2022 and the benefits to generation resource reduction were highlighted in the 2023 Integrated Resource Plan. In addition to the benefits of peak and energy reduction achieved with CVR/VVO, the program also provides more localized grid benefits including better voltage management and increased capability to support DER. Paired with the ADMS, controllable capacitors and voltage regulators installed by the program enable circuits to operate reliably in the lower portion of the allowable voltage range. This reduces energy consumption and allows more DER to be installed before high voltage concerns would arise. The capacitor placement and control program will be coordinated with the CVR/VVO program to replace aging capacitor controls on circuits in advance of CVR/VVO deployment. Details around these programs can be found in the Appendix Section C.1 - Grid Automation Investments.

NWA Projects

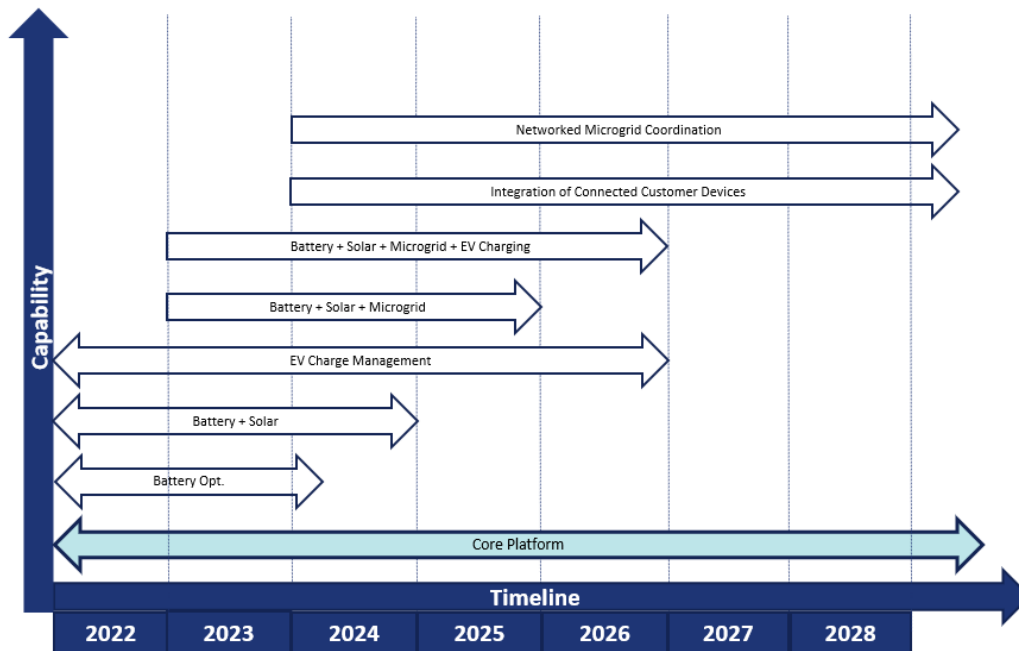
Non wire Alternative projects were discussed in more detail in the prior 2021 Distribution Grid plan, however, there have been some updates to the approach to NWA and DER integration. A key aspect of the Company's approach to NWAs is to have a consistent set of functionalities and controls. The initial NWA focus on single functions such as using battery storage for peak shaving or managing a battery with solar for smoothing. More advanced projects start to combine these functions together for further optimization and with microgrid capabilities, culminating in coordinated microgrids that implement some or all the optimization functions. The most advanced

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

NWA projects build on each other and integrate more functionalities such as combining energy storage management, solar management and EV charge management with monitoring and control of customer devices. Exhibit 10.1.1.3 below depicts the Company's levels of maturity and functionality for NWAs.

Exhibit 10.1.1.3: NWA Maturity and Functionality

Grid Edge Enablement, and Vehicle Electrification

The Grid Edge Enablement program and Vehicle Electrification Projects are implementing the functions and processes to enable DER and EVs to integrate with the grid so that these assets can be controlled by the utility to optimize the distribution system of the future. A key aspect of these programs is to coordinate the controls with grid automation devices and the ADMS applications to increase the value of DER and potentially minimize future investment. A standardized Interconnection Gateway (discussed in more detail in the Appendix C.1 Section - Grid Automation Investments) allows more software functions to be added to the gateway core platform, so that future projects benefit from a standardized approach in both controls design and processes.

The vision is to have a consistent hardware and software platform with modular functions that can be enabled as a project needs them. This allows for consistency of implementation, which can be communicated to customers early, and greatly reduces design and engineering costs once functions have been integrated.

AMI Future Planning

Advanced Metering Infrastructure (AMI) remains central to many of the Company's ongoing and upcoming capital investments. Originally designed and implemented to address real world customer challenges with billing accuracy and overall efficiency, DTEE implemented AMI to eliminate meter reading errors, reduce instances of estimated billing, and move away from manual meter reading. Over the last 14 years, DTEE has systematically executed to achieve those goals and as a result now has an industry-class system that delivers on those important customer-based outcomes.

In addition to these traditional use cases, supporting improved customer reliability has become critically important. AMI can help with many reliability efforts including locating system damage, determining what repairs are needed, determining each customer's power status, and reducing how often power is interrupted. These processes rely heavily on the AMI systems, which were not initially developed and implemented to deliver reliability benefits. While the Company continues to find ways to use the AMI system better, DTEE has reached the point where the future of AMI needs to be addressed to meet the reliability needs discussed above. It is essential that the AMI system of the future meet several criteria:

- Capable of different types of architecture because the Company now requires a design that can deliver reliable, near-real-time sensing of power status down to the meter level rather than simple historical meter usage information after the fact. Power status information would also require the ability to detect open neutrals.
- More resilient and fault tolerant so the AMI system can be used for operations in addition to using it for static billing, which was the original design basis.
- More flexible in its capabilities to allow for the use of different tariffs, and more specific time of day rates for various uses of energy.
- Capable of supporting new use cases including DERs, which requires more complex metering configurations to accurately separate generation, storage, and load and provide near-real-

time reads to inform the ADMS tools of important electrical grid variations due to EV charging, vehicle to grid support, energy shifting with storage, weather-dependent generation and active control schemes used by customers and third-party aggregators. New advanced meters may be able to provide control and submetering of separate connections at the same meter box which would greatly improve the management of DERs, EV charging, and demand response of large residential loads.

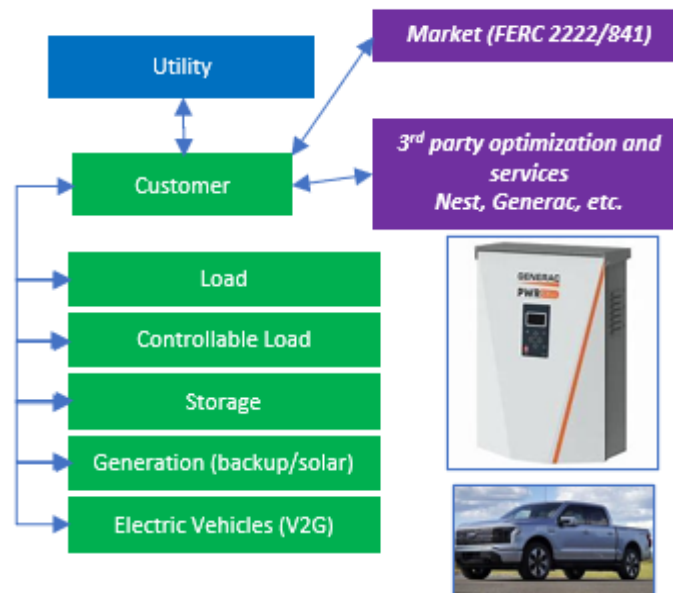
10.2 Operational Technology Roadmap

While the Grid Automation program forms the cornerstone of technology investments over the next five years, there are multiple other important investments being made which make up the Operational Technology roadmap; these are summarized in the investment area sections below. Within each section, we have also highlighted the investments and timing along with the corresponding applications and components of the DSPx model.

10.2.1 Grid Management Investments

Changes in customer capabilities such as controllable load, demand response, energy efficiency, on site generation, storage, electrification of HVAC and vehicles, vehicle to grid and microgrid technologies create needs for advanced grid management technologies. The diagram below (Exhibit 10.2.1.1) shows the various commercially available DER options to customers. In addition, these grid management technologies need to coordinate with advanced inverter and storage control modes that can produce or consume real and reactive power and impact grid performance. Individual DER in the field will need to be enabled to fully support this effort to unlock the benefits.

Exhibit 10.2.1.1: DER Options Commercially Available to Customers



Communication to end point devices and between end point devices is increasingly important as capacity margins decrease and less traditional stability is provided by central generating resources and variable power generation. The distribution system needs to be built for coordinated bi-directional power flow. Resources directly connected to the grid can include generation or storage and can have the potential to work as non-wire alternatives. To be able to provide Midcontinent Independent System Operator (MISO) requested grid services,⁴⁹ the assets need to be able to coordinate with other grid controls and other DER and have predictable behavior and interfaces. Operating and Planning processes also need to incorporate the capabilities of this new technology. These fundamental changes in customer capabilities form the basis for investment in DERMS (Distributed Energy Resource Management System) and enhancements to the ADMS, as the system used to manage the distribution grid, and to support coordination with DER.

⁴⁹State of Common Grid Services Definition, retrieved on (09/21/2023), https://eta-publications.lbl.gov/sites/default/files/gmlc_state_of_grid_services_report.12.12.22.pdf

Michigan Public Service Commission
DTE Electric Company
2023 Distribution Grid Plan U-20147

Objectives

- Visibility and control of the system
- Integration of Distributed Energy Resources
- Compliance to market and regulatory requirements
- Efficient management of automation assets and configurations

Key Investments

Exhibit 10.2.1.2: Key Investment Highlights for Grid Management

Key Investment	Use Case Description	Implementation Highlight and Customer Benefit	DSPx Objective
ASOC	Includes electronic displays and software/hardware that meet dispatcher and operator needs and mimic the current ESOC standards	Allows for a fully functioning, alternate location to carry-on the activities of the current Headquarters ESOC seamlessly, in the event of an emergency	Distribution Management System, Outage Management System
ADMS Enhancements	Enhance the integration, performance and capabilities of the ADMS	More efficient restoration and planned work coordination.	Enhances and further integrates components of the ADMS such as Real Time Power Flow Analysis, Distribution Management System, Outage Management System and Distribution Network model
EFC/PPS Storm Enhancements	Continue to improve customer outage status communications and storm response technology	More accurate outage status and restoration communications to customers and improved storm response systems	Outage Information
Meter Improvements	Improve meter situational awareness and use of energization as an outage management tool	Reduce improve outage estimates and communication, reduce okay on arrivals and improve dispatch of correct crew type	Advanced meters and Smart Meters, Operational Communications Outage Information

FLISR	Fault Location, Isolation and Service Restoration in ADMS	Minimize the scope of an outage through fault location and automated switching and optimizing restoration	DMS, Fault Analysis, SCADA, Automated Field Devices
DERMS Program	Distributed Energy Resource Management System provides interfaces for ADMS to communicate with DER, aggregations and market programs.	Optimize the dispatch of DER and offer new DER programs, integrate more DER into the system and improve the reliability of the grid	DER Portfolio Optimization, DER Management, Customer DER programs
Cyber security tools Program	Establish standardized tools, hardware and practices for maintaining cyber security at all points of the network	Harden the grid against cyberthreats	Cybersecurity of the operational communications network, Automated field devices, customer DER and interactions with DER Provider systems
Automation Configuration Database Project	Database for storage of relay and automated device settings. Replace existing database with an industry standard. Purchase new test sets that can automate settings and test management	Increase efficiency and accuracy of automation equipment installation and maintenance	Supports Operational data management for configurations and settings of SCADA, Automated field Devices and Advanced Protection

Exhibit 10.2.1.3: Key Investment and Timeline for Grid Management

Key Investment (in millions)	2024	2025	2026	2027	2028
ASOC	\$3.9	-	-	-	-
ADMS Enhancements	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0
EFC/PPS Storm Enhancements	\$5.6	\$1.4	\$1.4	\$1.1	\$0.4
Meter Improvements	\$1.4	\$1.4	\$1.4	\$2.8	\$2.8
Microwave End of Life	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5
FLISR	\$7.4	\$6.4	\$6.4	\$6.4	\$5.9
DERMS Program	-	\$1.5	\$2.8	\$2.8	\$2.8
Cyber Security Tools Program	\$0.8	\$0.8	\$0.5	\$0.5	\$0.5

Automation Configuration Database Project	\$1.4	\$3.2	\$3.2	-	-
Other Grid Management	\$2.2	\$3.5	\$1.7	\$1.4	\$1.4
Total	\$30.2	\$25.7	\$24.9	\$22.5	\$21.3

10.2.1.1 ASOC

ASOC is located inside the Waterford Service Center and is comprised of approximately 16,300 square feet with back-up generation and double redundancy for wireless and internet capabilities.



Construction on the Waterford Service Center in Waterford, Michigan, began in November 2022. The construction portion of the ASOC buildout will be completed in December of 2023, and completion of the furniture, fixtures and finishes as well as the technological fit out of the space will continue into 2024 for approximately 4-6 months. The ASOC is expected to achieve full NERC certification in 3rd quarter of 2024.

The design of both the ESOC and the ASOC is based on extensive benchmarking with many top tier utilities and industry experts. This facility includes electronic displays and software/hardware that meet dispatcher and operator needs and mimic the current ESOC standards. This will allow for a fully functioning, alternate location to carry-on the activities of the current Headquarters ESOC seamlessly, in the event of an emergency, as well as provide for the future training/re-training and testing of Emergency System Operation Centers employees. This will improve the resiliency of the system by providing redundancy.



10.2.1.2 Core Grid Management

Primary control of the distribution system is through the ADMS (Advanced Distribution Management System). The OMS (Outage Management System) and DMS (Distribution Management System) portions of the ADMS system were deployed in February of 2023 and will

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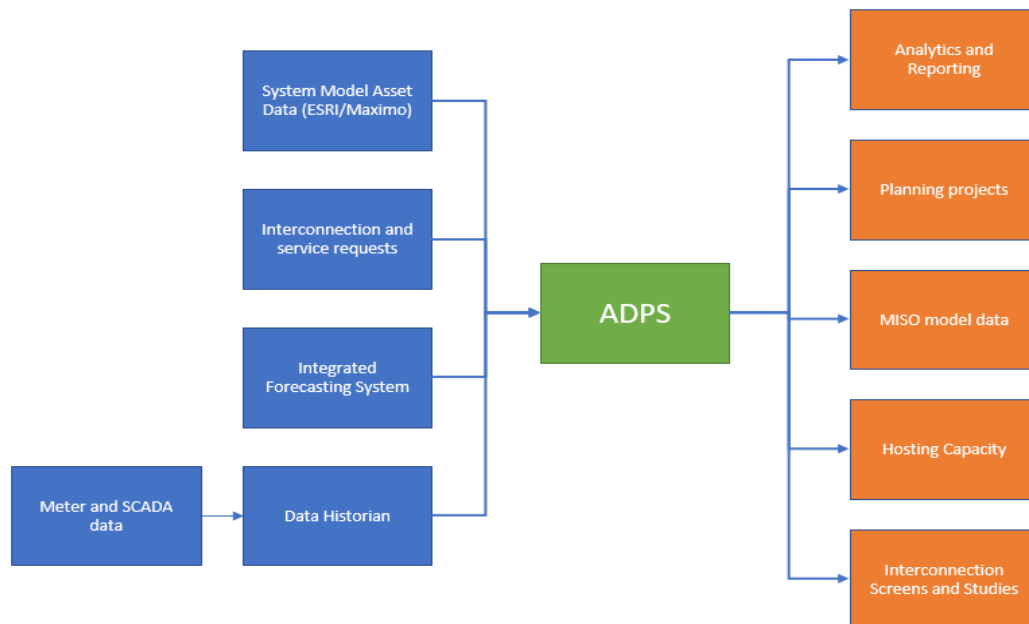
2023 Distribution Grid Plan U-20147

continue to receive upgrades and enhancements throughout the 2024-2028 period as evolving customer trends and demands on the grid require them. The key area of investment over this period will be the activation and expansion of FLISR (Fault Locating and Isolation with Service Restoration). The ADMS FLISR application will be used to automatically determine the location of a fault and recommend and execute switching operations, restoring power quickly to those not directly impacted by a fault. FLISR is a key complement to the larger automation program, as it enhances the value of the distribution automation devices being deployed in the distribution automation section of the report.

10.2.2 Distribution Planning Investments

The Advanced Distribution Planning System (ADPS) is the name for a suite of planning tools that work together to model and plan distribution system investments discussed in this Distribution Grid Plan. Investments incorporate enhancements to existing tools, new tools, and interfaces to allow more frequent and accurate modeling of the distribution system and planned changes. ADPS is made up of a number of core components including CYME, Power Runner, SEEQ and PSSE. These individual tools are used by planning engineers in modeling grid impacts. The ADPS system is tied directly to the automation strategy as it implements the planning toolsets used to evaluate system loading and reliability benefits of automation installations. The longer-term investments in this category will support the grid modeling needed for the expected increased penetration of DER. This section addresses the investments in Hosting capacity, Interconnection processing, Distribution planning, Power Quality analysis, DER and load forecasting and power flow analysis.

Exhibit 10.2.2.1: General Configuration of the Advanced Distribution Planning System



Drivers (DER, MISO, AFS, FERC2222)

A roadmap for planning tool investments has been established to align with multiple regulatory requirements and the availability of more complex DER functionality that creates a need for more complex modelling and simulation of the electrical system and requires upgrades to planning tools. Traditional distribution planning has been focused on a single point in time for each year, the annual peak load. However, as DER become more common and dispersed throughout the distribution grid, the day to day and hourly variability of load and generation needs to be modelled to ensure the system is designed to reliably handle the variability in grid load and other characteristics.

Recent MPSC changes to the interconnection rules introduced screening criteria requiring utilities to perform rapid studies of circuit and line segment level minimum loading analysis. Future MISO modelling requirements through MOD-32 require studies to be done on gross load rather than net load, and disaggregation of all distribution DER by type of generation, voltage control mode, and dynamic models for distribution DER aligned to the transmission nodes in the MISO model.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

FERC 2222 will require additional validation studies for distribution and aggregated DER that is seeking market participation and periodic restudy to validate that circuit operating criteria is not violated. In addition to the modelling tools themselves, investments are needed to properly contextualize the data for stakeholders while maintaining the security of the grid data and Critical Energy Infrastructure Information (CEII).

Peak loading and reliability analysis will continue to be a critical aspect of project planning for all projects, as it identifies times of maximum load current and areas that may experience low voltage and how circuits will be operated to improve reliability. This functionality is complicated by incorporating new DER which may mask the actual peak load or change how the system must be operated. Interconnection studies typically identify times of minimum or reverse power flow and high voltage as well as the impacts to the grid and are critical for complying with the interconnection and system modelling processes to ensure grid stability. DER in the form of storage requires analysis of available energy to charge and the ability for the circuit to handle the discharge. This analysis requires a more granular load allocation at the hourly level. Grid upgrades, customer loads, and DER interconnections simulations need to be coordinated and sequenced according to their construction schedules to ensure that the grid remains reliable during these significant changes.

With these complexities introduced through DER integration, the system design tools that perform studies for capital projects and operational verification need to be upgraded to incorporate forecasts, DER variability, time dependent loading and multi scenario analysis, and increased integration between distribution planning tools and subtransmission and transmission modelling. All these factors are considered and addressed in the ADPS investments. More details are provided in the Distribution Planning Investments Section-Appendix C.3.

Objectives

- Efficient grid simulation tools that incorporate DER and NWA analysis
- Multi scenario analysis and forecasting
- Regulatory compliance for interconnection and FERC rules
- Streamlined design tools that facilitate standards

Key Investments

Exhibit 10.2.2.2: Key Investment Highlights for Distribution Planning

Key Investment	Use Case Description	Implementation highlight and Customer Benefit	DSPx Objective
Network Management System (NMS) Phase 2	Management of GIS, asset and system model data for use by the ADMS and System Planning tools	Improved cohesion of utility data systems; enhanced accuracy of distribution model improves all functions that are essential to safe and effective planning, monitoring, and operation of the electrical grid	Operational Data Management, Distribution Network model
Load Allocation Analytics	Data consolidation and analytics platform that integrates hourly SCADA loading information, AMI loading and load forecast data into a single analytics and reporting engine that can be used by other operational and planning tools and distribution system programs	Improved accuracy of system loading models improves results of distribution planning analysis leading to better project designs and more efficient investment of capital system improvements.	DER & Load Forecasting, Operational and Data Management, Locational Value Analysis
CYME Enhancements Program	Distribution planning tool enhancements to incorporate power runner data to perform hourly multi scenario analysis for DER and system improvements	More accurate distribution system planning leading to optimized distribution system capital investments, more integration of DER, Storage, Non-Wire Alternatives and being prepared for electrification.	Power Quality Analysis, Fault Analysis, Power Flow analysis, Probabilistic Planning, Locational Value Analysis
Forecasting and Propensity Analysis Program	Analysis tools to create locational forecast scenarios for DER and electrification adoption, integrate with system load forecasting and feed this data to planning tools	Improved mid to long range scenarios to evaluate distribution planning projects against to better optimize capital investments.	DER & Load Forecasting, DER Portfolio Optimization, Probabilistic Planning

Interconnections Process Enablement Program	Improvements to Interconnection tools and processes, Compliance requirements for State and Federal Interconnection programs	Streamlined interconnection application, screening, and study	DER Management, Customer DER Programs, Customer DER Decision Support Analytics
Hosting Capacity Program	Enhancements to publicly accessible Hosting Capacity data resolution, updates and inclusion of Loading capacity	Improved customer access to system data relevant to new DER and load integration	Hosting Capacity, Customer DER Decision Support Analytics, Grid Data Portal, DER provider Data
Sub transmission planning Program	Sub transmission planning tool enhancements integrate distribution system and DER data and keep compliant with MISO modeling requirements	More accurate sub transmission system planning leading to optimized system capital investments and system resiliency planning, more integration of DER, Storage, Non-Wire Alternatives and being prepared for electrification	Power Quality Analysis, Fault Analysis, Power Flow analysis, Probabilistic Planning, Locational Value Analysis, Dynamic Analysis
Power Quality Analysis Program	Tools to improve the collection, processing and analysis of faults, grid disturbances and power quality events	Improved detection of grid anomalies and root cause analysis of outages and failures will help identify future outage risks, eventually leading to incipient failure detection and proactive measures to mitigate or prevent outages where possible	Power Quality Analysis, Fault Analysis, Dynamic Analysis
Substation and Structural Design Program	Structural and CAD Design tool enhancements to improve design accuracy, efficiency, standardization, and compliance	More efficient and timely design of capital investment projects	Supports engineering, design, and Implementation of Physical grid Infrastructure

Exhibit 10.2.2.3: Key Investment and Timeline for Distribution Planning

Key Investment (in millions)	2024	2025	2026	2027	2028
NMS Phase 2	\$1.6	\$2.8	\$2.1	\$1.5	-
Load Allocation Analytics	\$2.2	\$1.0	\$2.0	\$2.5	\$0.8
CYME Enhancement program	\$1.3	\$1.5	\$1.5	\$1.5	\$1.5
Forecasting and propensity analysis Program	\$0.2	\$1.8	\$0.7	\$0.4	\$1.5
Interconnections process enablement Program	\$1.9	\$1.7	\$1.7	\$1.8	\$1.5
Hosting Capacity Program	\$0.5	\$0.3	\$0.4	\$0.3	\$0.5
Sub transmission planning Program	\$0.4	\$0.3	\$0.3	\$0.3	\$0.3
Power Quality Analysis Program	\$0.4	\$0.5	\$0.4	\$0.5	\$0.4
Substation and structural design Program	\$1.9	\$1.2	\$1.5	\$0.8	\$0.5
Other Distribution Planning	\$1.6	\$2.2	\$0.5	-	-
Total	\$12.0	\$13.3	\$11.1	\$9.6	\$7.0

10.2.3 Work Management and Scheduling Investments

As DTEE increases investments in its distribution grid and focuses on automation, the higher workload and job complexity will require the company to advance its work management systems and processes. The work management process includes scheduled and unscheduled work, work order creation, resource scheduling, and tracking work execution for employees, vendors and third-party crews. Work management tools also include job planning, labor, material, tools and services for both large, complex work efforts and smaller, short-term jobs. Upon completion, work must be audited and verified for payment purposes.

Objectives

- Visibility into the status of work as it moves through the planning, scheduling and execution pipeline

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

- Awareness of crew and contract resource availability on a weekly and daily basis
- Schedule optimization and prioritization
- Ensure all time worked is properly applied to jobs
- Ability for all resources executing work to access electronic job information and electronically verify completion

Key Investments

Exhibit 10.2.3.1: Key Investment Highlights for Work Management and Scheduling

Key Investments	Use Case Description	Implementation highlight and Customer Benefit	DSPx Objective
DO Maximo Transformation	Implementing a separate Maximo environment for DO to support DTEE-specific processes and optimizations	Increased operational efficiency with planned work will lead to faster modernization of the grid	Operational Data Management, management of Physical Grid Infrastructure and Distribution Network Model information
Enhance Maximo capabilities and processes	Optimizing Maximo for electric distribution operations and work management	Increased operational efficiency with planned work will lead to faster modernization of the grid	Operational Data Management, management of Physical Grid Infrastructure and Distribution Network Model information, Scheduling of Physical Grid Infrastructure
Substation Reporting and Process Enhancements	Expand integration to include crew work data within Maximo	Improved productivity will maintain service affordability	Operational Data Management
Primary Service Orders Replatform	Replatform the technology that supports processes that serve primary customers	Faster restoration outcomes for primary customers	Operational Data Management, Distribution Network Model and GIS
External Crew Efficiency	Collect and process work time and associated data from external crews performing work for DTEE	Streamlined crew tracking will reduce administrative costs associated with this work and maintain service affordability	Operational Data Management

Exhibit 10.2.3.2: Key Investment and Timeline for Work Management and Scheduling

Key Investment (in millions)	2024	2025	2026	2027	2028
DO Maximo Transformation	\$4.2	\$7.0	\$7.0	\$7.0	-
Enhance Maximo capabilities and processes	-	\$0.8	\$1.1	\$1.4	\$2.1
Substation reporting and process enhancements	\$0.4	-	-	-	-
Primary Service Orders Replatform	\$2.0	\$4.1	\$1.1	-	-
External Crew Efficiency	\$2.0	\$0.8	-	-	-
Other Work Mgmt & Scheduling	\$1.4	\$1.0	\$0.6	-	-
Total	\$10.0	\$13.7	\$9.8	\$8.4	\$2.1

10.2.4 Asset Management Investments

Managing the electric grid relies heavily on maintaining and replacing distribution assets, thereby requiring systems that can effectively manage this critical function. The overall goal of effectively managing assets is to minimize the total cost of ownership and operations while delivering desired service levels. This includes maintaining access to accurate digital data about the asset, algorithms to process and analyze data, and a visual context of an asset's location and condition.

Objectives

- Ability to manage asset processes online or offline, regardless of wireless connectivity
- Improved timeliness of asset updates from the field and support for map-centric asset management
- Ability to track labor, materials, and tools charges by all asset types and linear measures
- Increased presence and frequency of asset assessments to better monitor asset health
- Modernization of asset tracking through mobile technology, including health and location monitoring.

Exhibit 10.2.4.1: Key Investment Highlights for Asset Management

Key Investment	Use Case Description	Implementation Highlight and Customer Benefit	DSPx Objective
ESRI ArcGIS updates	Update and rearchitect ArcGIS system to eliminate redundancies	Streamlined architecture reduces overall cost of ownership and improves management of operational data	Operational Data Management, GIS
ESRI Utility Network Proof of Concept	Assessment and pilot of ESRI utility Network Model conversion and its impacts	Prepare for a successful transition to the Utility Data Model	Operational Data Management, GIS, Distribution Network Model
ESRI Map Data Conflation	Accurate positioning of GIS data to geo located coordinates and spatial data sets	More accurate right of way, maps, asset locations design to enable more efficiency in capital improvements	Operational Data Management, GIS, Distribution Network Model
ESRI Utility Network Conversion	Conversion of the ESRI database to the industry standard Utility Network Model and associated tools and processes	Improvements in data structures and management that more accurately reflects the electrical and physical systems of the grid and the change management processes for installing, maintaining and removing assets enabling much more efficiency updates to the ADMS and system planning tools and data interchange of system model information	Operational Data Management, GIS, Distribution Network Model
ESRI Field Tool Integration	Filed data capture of As Built designs, asset status and as found conditions	Improved accuracy of distribution system model, asset condition and field markup increases the efficiency and accuracy of all of the ADMS and planning and design tools leading to greater efficiency	Operational Data Management, GIS, field Capture of Physical Grid Infrastructure changes, Distribution Network Model

		of capital investment and trouble resolution	
Asset Assessment Frequency	Real time assessment of asset health	More targeted identification of assets that might need maintenance or replacement	Operational Data Management, Asset management of Physical Grid Infrastructure
Systematic Tracking of Rotatable Assets	Tracking rotatable assets and tools through their lifecycle using RFID	More effective maintenance of rotatable assets	Operational Data Management

Exhibit 10.2.4.2: Key Investment and Timeline for Asset Management

Key Investment (in millions)	2024	2025	2026	2027	2028
ESRI ArcGIS updates	-	\$0.6	-	\$1.1	\$0.6
ESRI Utility Network Proof of Concept	\$1.1	-	-	-	-
ESRI Map Data Conflation	\$0.3	\$2.2	\$1.4	\$1.4	\$1.1
ESRI Utility Network Conversion	-	-	\$4.2	\$4.2	\$5.6
ESRI Field Tool Integration	-	-	-	\$2.8	\$2.1
Asset assessment frequency	-	-	\$0.4	-	-
Systematic Tracking of Rotatable Assets	-	\$0.6	-	-	-
Total	\$1.4	\$3.4	\$6.0	\$9.5	\$9.4

10.2.5 Mobile Technology Investments

The goal of mobile technology investments is to create seamless transitions between on-line and off-line operations and provide integrated communication, including workflows, between the

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

control room, field leaders, field crews, and supporting organizations. Mobile capabilities include both devices and applications that are engineered for mobile access and usage. Applications include dispatch, work execution and forms digitization, location tracking, route navigation, analytics and secure file sharing.

Objectives

- Enhance daily work through mobile tools that provide timely and accurate information, as well as allow quick and easy capture of critical data in the field (including photos, markups, and videos)
- Enable point-of-activity applications that increase worker and leader time in the field
- Deploy optimized, task-based applications and mobile access to all intra-company systems and documents
- Improve time tracking of field workers work execution
- Modernize field crew tools and technologies to gain efficiencies through reduced manual effort, improved data quality, and accelerated customer service, including faster restoration and improved reliability

Key Investments

Exhibit 10.2.5.1: Key Investment Highlights for Mobile Technology

Key Investment	Use Case Description	Implementation Highlight and Customer Benefit	DSPx Objective
Mobile Tools Expansion	Expand tools that allow workers to execute their work completely from the point of activity	Improved efficiency through point-of-activity data transactions; increased employee engagement; centralized operational data through system integrations	Operational Data Management
Maintain Compliance	Ensure compliance with regulatory and industry mandates and requirements	Continued compliance with all relevant mandates around the use of operational, customer, and payment data	Operational Data Management

	related to the use of operational data		
Enhance and Expand Cybersecurity	Maintain cybersecure technologies that remain safe against the expanding threat landscape	Heightened security vigilance maintains security and integrity of customer and operational data	Operational Data Management
Mobile Equipment Replacement	Replace end-of-life mobile hardware used by field workers	Field workers that can execute work from the field without interruption	Operational Data Management

Exhibit 10.2.5.2: Key Investment and Timeline for Mobile Technology

Key Investment (in millions)	2024	2025	2026	2027	2028
Mobile Tools Expansion	\$1.1	\$0.8	\$0.7	\$1.1	\$1.1
Compass Mobile Tool	\$1.6	-	-	-	-
Maintain Compliance	\$0.6	\$0.6	\$1.1	\$0.6	\$0.4
Enhance and Expand Cybersecurity	\$0.8	\$0.8	\$0.8	\$0.8	\$0.8
Mobile Equipment Replacement	\$2.8	\$2.8	\$1.4	\$4.2	\$7.0
Other Mobile Technology	\$1.3	\$0.8	\$1.1	\$1.0	\$1.0
Total	\$8.2	\$5.8	\$5.1	\$7.7	\$10.3

11 Summary of Investment Plan

The overall investment levels are shown in Exhibit 11.0.1, with more detail by pillar and program shown in Exhibit 11.0.2. These investments represent all capital investments, and the two key maintenance programs (tree trimming and preventive maintenance).

Exhibit 11.0.1 Projected Distribution Grid Plan Investments

		\$ Millions					
Category		2024	2025	2026	2027	2028	5-Year Total
Capital Investments (\$ Millions)							
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	\$415	\$399	\$368	\$348	\$345	\$1,877
	Customer Connections, Relocations and Others	\$282	\$295	\$314	\$334	\$355	\$1,580
Strategic Capital Programs (details in Exhibit 11.0.2)		\$906	\$995	\$1,134	\$1,302	\$1,485	\$5,821
Total Capital Investments		\$1,603	\$1,689	\$1,816	\$1,985	\$2,185	\$9,278
Maintenance Programs (\$ Millions)							
Tree Trimming		\$123	\$140	\$101	\$103	\$106	\$573
Preventive Maintenance		\$10	\$10	\$10	\$10	\$10	\$50

Exhibit 11.0.2 Projected Distribution Grid Plan Investments (Sorted by Reference Section Number)

Programs	\$ Millions						Reference Section #
	2024	2025	2026	2027	2028	5-Year Total	
Infrastructure Resilience & Hardening							
Pole and Pole Top Maintenance and Modernization	\$121	\$121	\$151	\$192	\$188	\$773	8.1

4.8 kV Hardening	\$80	\$95	\$54	-	-	\$229	8.2
4.8 kV Automatic Pole Top Switch (APTS)	\$5	\$5	\$7	\$7	\$7	\$32	8.3.1
SCADA Pole Top Device	\$2	\$2	\$2	\$3	\$5	\$14	8.3.1
Steel Pole Highway Crossings	\$3	\$5	\$5	\$5	\$5	\$25	8.3.1
System Cable Replacement	\$21	\$20	\$20	\$20	\$20	\$102	8.3.2
Underground Residential Distribution (URD) Cable	\$15	\$15	\$15	\$15	\$15	\$75	8.3.2
Subtransmission Disconnect Switches	\$3	\$3	\$3	\$3	\$3	\$15	8.3.3
Circuit Switchers	\$2	\$2	\$2	\$2	\$2	\$10	8.3.3
Circuit Breakers	\$14	\$15	\$15	\$15	\$15	\$74	8.3.3
Substation Regulators	\$1	\$1	\$1	\$1	\$1	\$4	8.3.3
Batteries & Chargers	\$3	\$3	\$3	\$3	\$3	\$15	8.3.3
Substation Outage Risk	\$51	\$2	\$6	\$17	\$17	\$92	8.5
Station Upgrades	\$5	\$9	\$14	\$8	\$4	\$40	8.5
Mobile Fleet	\$5	\$2	\$2	\$2	\$2	\$12	8.5
Frequent Outage (CEMI) including Circuit Renewal	\$48	\$20	\$20	\$20	\$20	\$128	8.6
Infrastructure Redesign & Modernization							
System Loading	\$47	\$75	\$59	\$100	\$100	\$381	9.1
Subtransmission Redesign & Rebuild	\$100	\$100	\$108	\$108	\$108	\$524	9.2
4.8 kV Conversion and Consolidation	\$76	\$76	\$195	\$253	\$320	\$919	9.3

City of Detroit Infrastructure (CODI)	\$95	\$126	\$148	\$119	\$90	\$579	9.3
8.3 kV Conversion and Consolidation	\$19	\$31	\$29	\$18	\$18	\$114	9.3.7
Strategic Undergrounding	\$15	\$5	-	-	-	\$20	9.4
Technology & Automation							
Grid Automation	\$62	\$163	\$191	\$309	\$469	\$1,192	10.1
Grid Automation Telecommunications	\$17	\$15	\$14	\$13	\$11	\$69	10.1
CVR/VVO	\$5	\$5	\$5	\$5	\$5	\$25	10.1
Capacitor Replacement and Control Program	-	\$6	-	-	-	\$6	10.1
NWA Projects	\$15	\$1	\$0	-	-	\$16	10.1
Grid Edge Enablement program	\$6	\$4	\$4	\$3	\$3	\$20	10.1
Vehicle Electrification Projects	\$3	\$1	\$1	\$1	\$1	\$6	10.1
Line Sensors	\$1					\$1	10.1
URD Fault Indicators	\$3	\$3	\$3	\$3	\$3	\$15	10.1
Large/Medium Sized DER Monitoring and Control	\$0	\$0	\$0	\$0	\$0	\$2	10.1
New Technology Evaluation Program	\$1	\$1	\$1	\$1	\$1	\$5	10.1
Grid Management	\$30	\$26	\$25	\$23	\$21	\$125	10.2.1
Distribution Planning	\$12	\$13	\$11	\$10	\$7	\$53	10.2.2
Work Management and Scheduling	\$10	\$14	\$10	\$8	\$2	\$44	10.2.3
Asset Management	\$1	\$3	\$6	\$10	\$9	\$30	10.2.4
Mobile Technology	\$8	\$6	\$5	\$8	\$10	\$37	10.2.5

12 Work Prioritization



12.1 Investment Selection Methodology

A robust method to evaluate and prioritize investments in the electric grid is fundamental to developing an investment plan that delivers the most benefit for customers. The gaps to future state were discussed in Section 5, and the investments that will help close those gaps are discussed in Sections 7 through 10. The investment needed to fully close these gaps is substantial and will require investments beyond the timeline of this DGP. The goal of the Company's investment selection methodology is to evaluate programs and projects and prioritize the funding of investments which deliver the broadest set of benefits to our customers and improvements to our grid within our capital portfolio.

The DSPx framework describes some of the challenges of evaluating traditional grid investments. The first challenge is that grid investments often provide multiple benefits, which can be impossible to disaggregate. For example, converting an overhead circuit to a higher voltage will provide increased capacity, improved safety and better reliability. A new substation, particularly one which replaces an older substation, will reduce the risk of a major substation outage, provide capacity for new load and reduction of emergent costs. Both types of projects deliver multiple interconnected benefits as part of the investment. The second challenge is that most of these benefits, such as safety, reliability and risk, cannot be easily or appropriately translated into a dollar amount. These two challenges to quantifying project benefits are referred to as "joint and

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

interdependent benefits.” To prioritize investments with joint and interdependent benefits, a simple analysis comparing costs to benefits cannot be undertaken. Rather, the GPM is based on an economic evaluation method known as “best-fit, most-reasonable cost.”

DTEE has used this method to prioritize investments since the Global Prioritization Model (GPM) was developed in 2018. The most recent update of the GPM measures ten separate benefits that projects and programs deliver to customers. Each benefit is called an ‘impact dimension,’ and each impact dimension has one or more drivers which are measured to quantify a benefit. Projects and programs are given scores in each dimension (generally ranging from 0 to 100) based on the amount of expected benefit divided by the total investment (in most cases). Projects that deliver more benefits per dollar invested will receive higher scores in that dimension. The score in each dimension is multiplied by a weighting factor for that dimension. The weighting factors enhance the scores of projects that provide benefits in core reliability and safety. The dimension scores are added together to provide a total project or program score. The projects and programs with the higher scores provide more benefits and are prioritized for implementation. This method results in a portfolio where projects that deliver the most value improving safety, reliability, and load relief, are prioritized for earlier investment. The list of impact dimensions and weightings are shown in Exhibit 12.1.1 below.

Exhibit 12.1.1 Global Prioritization Model Impact Dimension

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	- Reduction in wire down events - Reduction in secondary network cable manhole events	3
Overload Relief	Elimination of overloaded equipment	
SAIDI	Reduction in duration of outage events	
SAIFI	Reduction in frequency of outage events	
Regulatory Compliance	- MPSC staff’s recommendation (March 30, 2010 report) on utilities’ pole inspection program - Docket U-12270 – Service restoration under normal conditions within 8 hours - Docket U-12270 – Service restoration under catastrophic conditions within 60 hours	2

	• Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	1
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	

The Company has made four enhancements to the GPM model based on input from stakeholders and the Commission, and in line with the enhancements that were discussed in the 2021 DGP.

- 1) The impact dimension which was previously named “Load Relief” has been divided into “Overload relief” and “Capacity relief.” The former addresses equipment which is overloaded under normal conditions. Capacity relief addresses substations operating over firm and many of the planning criteria on the subtransmission system. This dimension also incorporates the 15-year loading forecast that will more fully incorporate potential customer adoption of new technologies such as EVs and DER.
- 2) The impact dimension of “SAIFI” was added to complement SAIDI, and account for reduction in frequency of outages as well the overall importance of improved reliability.
- 3) “Investment in EJ communities” was added to formally incorporate prioritization of EJ communities into the investment planning process
- 4) The weighting of dimensions was simplified and changed from a 10-point scale to a 3-point scale.

The intent of these changes is to more fully account for the grid benefits that many of the investments bring to our customers, to incorporate feedback heard about the GPM, and to simplify the framework. These updates to the GPM were presented at the DGP Technical Conference on August 31, 2023.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

12.1.1 Interruption Cost Estimate (ICE) Calculator 2.0 and the Value of Reliability

As discussed above, many of the benefits which grid investments deliver are quantifiably but not easily translated into monetary terms. Reliability improvements fall into this category. One commonly used method to value reliability is the ICE calculator, which was developed by Lawrence Berkeley National Laboratory (LBNL). In the 2021 DGP, the company discussed many of the limitations of this version of the ICE calculator.

To provide more meaningful results quantifying the value of reliability, LBNL is developing the second iteration of the calculator, ICE 2.0. DTEE is a sponsoring utility for the development of this updated tool. As a sponsor, LBNL and DTEE are currently surveying DTEE customers across residential, commercial, and industrial segments, to quantify what economic impact outages have of them. This work will close gaps from the first ICE tool, which relied on decades old data and did not have a significant sample of Midwest customers or customers living in colder climates. The updated tool is expected to be released in 2024.

12.2 Environmental Justice

Environmental justice (EJ) is an evolving planning principle within DTEE's DGP.⁵⁰ DTEE established its commitment to EJ communities when first addressing them in the development of the 2021 DGP and then in the 2022 Integrated Resource Plan (IRP). Since then, the Company has taken measures to further incorporate EJ into distribution planning and continues to increase the meaningful engagement of customers within its vulnerable communities. The desire for this consideration of EJ was expressed clearly in the feedback DTEE collected from customers, leaders within vulnerable communities, and other stakeholders.

12.2.1 Identifying and Investing in Vulnerable Communities

The Company first began working on the concept of EJ in distribution planning with the 2021 DGP filing. Since the publication of that plan, the State of Michigan published the MiEJScreen tool,⁵¹

⁵⁰ Under the MI Healthy Climate Plan, environmental justice is defined as "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn See MI Healthy Climate Plan: <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588>, accessed September 5, 2023:

⁵¹ [MiEJScreen: Environmental Justice Screening Tool \(DRAFT\) \(michigan.gov\)](#)

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Witness: Kryscynski

Page: 169 of 274

which the Company now uses to identify vulnerable communities within the electric service territory. DTEE defines vulnerable communities as those with a composite MiEJScreen score at or above the 80th percentile. There are 483 census tracts in DTEE's service territory that meet this definition. These 483 census tracts represent 29% of the total census tracts in DTEE's service area and account for approximately 550,000 residential customers. By leveraging the census tract-specific EJ scores provided by the MiEJScreen tool, DTEE has been able to map reliability and investment projects and programs relative to where the most vulnerable customers reside.

Through this mapping, the Company is able to create a geographic representation of reliability data across the Company's service territory. Using the residential customer meters that are matched to census tracts, DTEE associated 2022 reliability data for SAIDI and SAIFI by census tract and grouped the data into DTEE reliability quartiles, with first quartile customers (shown below in green) experiencing the best reliability, and fourth quartile customers (shown below in red) experiencing the worst reliability. See Exhibit 12.2.1., Exhibit 12.2.1.2, Exhibit 12.2.1.3, and Exhibit 12.2.1.4 for maps with systemwide 2022 reliability quartile for vulnerable census tracts within DTEE service territory.

**Exhibit 12.2.1.1 2022 All Weather
SAIDI by Census Tract for DTE
Electric (Full Electric Service Area)**

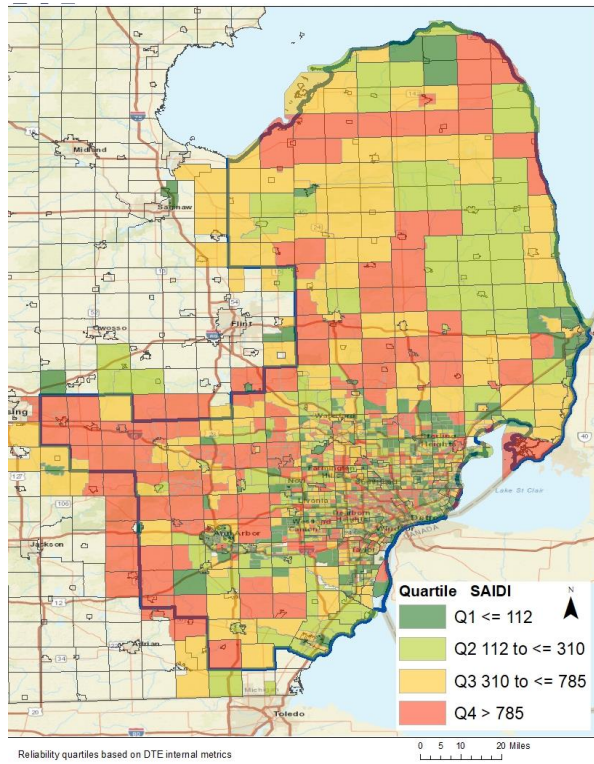


**Exhibit 12.2.1.2 2022 All Weather
SAIDI for Vulnerable Census Tracts
with MiEJ Score of 80% to 100%**

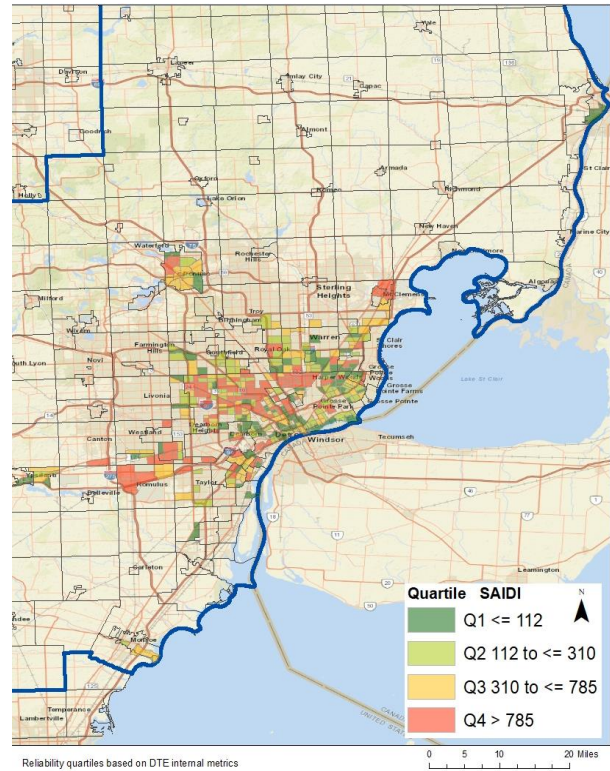


**Exhibit 12.2.1.3 2022 All
Weather SAIDI by Census
Tract for DTE Electric (Metro
Detroit Area)**

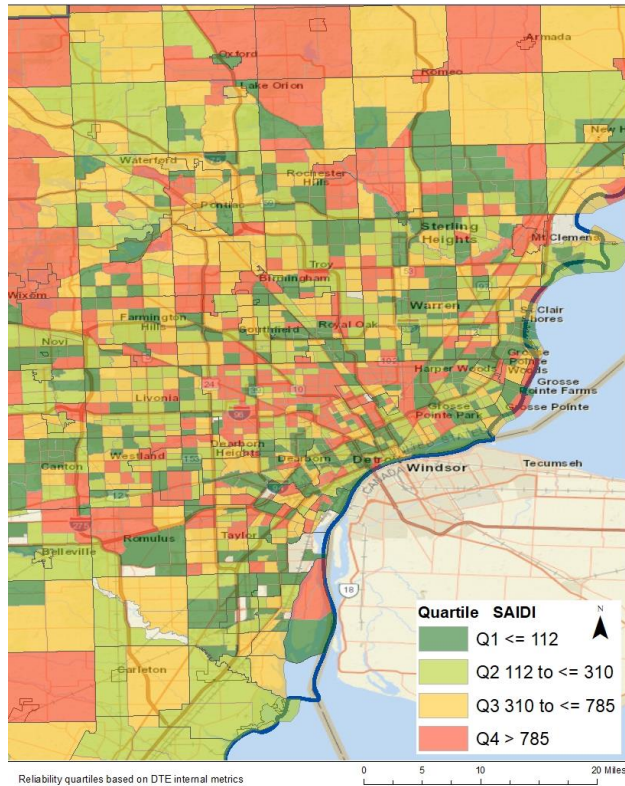
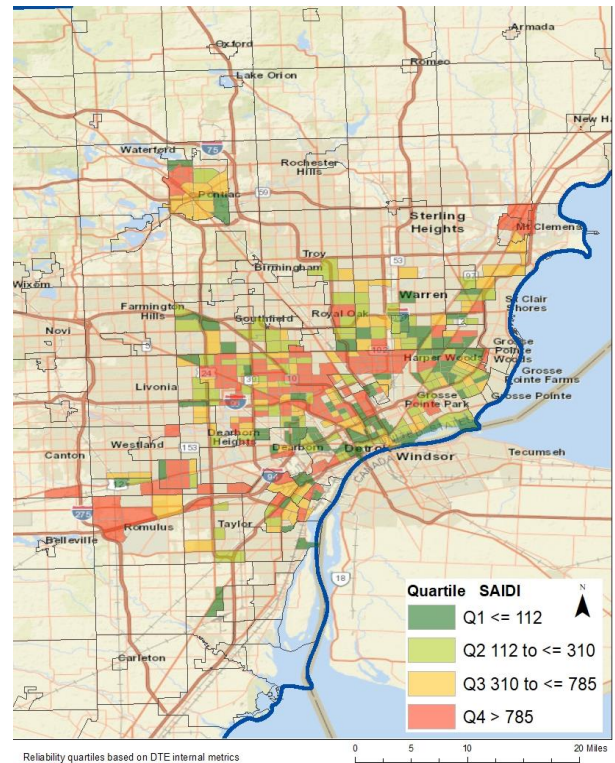


**Exhibit 12.2.1.4 2022 All Weather
SAIDI for Vulnerable Census Tracts
with MiEJ Score of 80% to 100%
(Metro Detroit Area)**



The Company conducted analysis to evaluate the reliability performance of census tracts in the vulnerable communities compared to the rest of the DTE Electric. The analysis of reliability performance in DTE's vulnerable communities demonstrates that the investments the Company has focused on vulnerable communities, in particular the City of Detroit, have resulted in improved reliability. The 483 census tracts have a range of performance that spans from first quartile to fourth quartile reliability performance in years 2020 through 2022 for SAIDI and SAIFI compared to the systemwide levels (see Exhibit 12.2.1.5). In addition, the Company conducted an analysis of its investment programs to assess how they are reaching vulnerable communities as shown in Exhibit 12.2.1.6. This analysis demonstrates that the Company has made significant distribution investments in its vulnerable communities in the past five years and plans to continue that investment into the future.

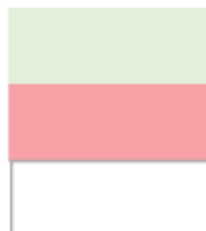
Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Exhibit 12.2.1.5 Reliability Performance of Vulnerable Census Tracts (MiEJ Score of 80% to 100%) Versus System Average

	2020	2021	2022
All weather SAIFI vulnerable communities	1.06	1.30	1.12
All weather SAIFI system average	1.29	1.58	1.25
Ex-MED SAIFI vulnerable communities	0.81	0.75	0.81
Ex-MED SAIFI system average	1.01	0.92	0.98
All weather SAIDI vulnerable communities	356	823	732
All weather SAIDI system average	352	927	584
Ex-MED SAIDI vulnerable communities	134	116	130
Ex-MED SAIDI system average	142	136	146



Over performing system average

Under performing system average

System average

Exhibit 12.2.1.6 Investments in Vulnerable Communities (Census Tracts with MiEJ Score of 80% to 100%)

Investment Program	% Of Investment in Vulnerable Communities	
	(2018 – 2022)	(2023-2026)
Conversion	75%	86%
4.8kV Hardening	89%	93%
Tree Trim	30%	14% ⁵²

In addition to these studies, in Order U-20836 dated September 18, 2022, the Commission requested that DTEE work with Staff and interested stakeholders to conduct a study examining the impacts of both socioeconomic data analysis and more comprehensive analysis of alternatives for the 4.8 kV system within the Company’s metro Detroit fiber loop.

Further discussion of the study including study results is included in Appendix E.

12.2.2 Engaging Vulnerable Communities in Distribution Planning

DTEE has been engaging customers in its vulnerable communities on the topic of distribution planning. Conversations with community members generated key themes, including:

- A desire to understand reliability performance at the local community level and compared to other communities
- How the investment programs identified in the DGP will translate into investment plans at the local level
- Timing of local investments
- Reliability improvement expected from investments

To continue these conversations, DTEE is keeping lines of communication open through direct conversations via meetings with block clubs, homeowners associations (HOAs), and resident meetings and with community leaders from faith-based organizations, social services agencies,

⁵² Tree Trim has not finalized the circuits to be trimmed in 2024 and beyond.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

advocacy organizations, and others. Detailed discussion of DTEE's overall engagement plan can be found in Section 14.2, Community Engagement.

12.2.3 Environmental Justice Plan and Actions

While DTEE is proud of the progress made to support vulnerable communities, the Company recognizes there will be ongoing efforts to ensure that the vulnerable communities continue to see improvements. Building on the 2021 DGP, the Company developed three key EJ objectives for the 2023 DGP:

1. Incorporate EJ considerations in investment decisions by including an EJ component in the Global Prioritization Model (GPM)
2. Improve system performance for vulnerable communities with the worst reliability through our investment programs (Tree Trim, PTMM, Conversion, Customer Excellence and 4.8kV Hardening)
3. Provide support to vulnerable customers experiencing outages during storms through community outreach efforts

Update Global Prioritization Model: For the 2023 DGP, EJ is now incorporated into the updated GPM model see Section 12.1. Exhibit 12.2.1 illustrates the addition of "Investment in EJ communities" as a new GPM impact dimension. All other criteria being equal, projects in vulnerable communities will have a higher GPM score and will therefore be prioritized over other projects with a similar GPM score based on the other impact dimensions. This will ensure that vulnerable communities are specifically considered in the prioritization process.

Improve System Performance: DTEE has identified 191 circuits in vulnerable communities which fall in the fourth quartile for reliability performance based on a five-year historic average. As shown in Exhibit 12.2.3.1, about 1/3 of the fourth quartile reliability circuits have already had a recent reliability investment and 2/3 of the circuits are planned to be addressed in 2023-2026 investment programs.

Exhibit 12.2.3.1 Investment of Circuits in EJ Communities that Falls in the 4th Reliability Quartile

Investment Category	191 total circuits in EJ communities fall within the 4 th reliability quartile	
	68 circuits had work completed 2018-2022	123 circuits have work planned 2023-2026
Conversion	1	11
4.8kV Hardening	49	88
Tree Trim	12	20
Subtransmission Upgrades	1	0
CEMI Program	5	0
Technology and Automation	0	4

Outage Response: DTEE continues to evolve outage response strategies supporting customers with considerations of impacts in vulnerable communities. Our storm response initiatives ensure relief is provided to vulnerable communities by deploying community vans with essential supplies, supporting warming and cooling centers, in vulnerable communities, performing safety checks at the homes of senior customers and by ensuring there is clear and consistent communication to all affected customers and community leaders during a storm event.

Conclusion

DTE Electric has made progress and plans to further evolve considerations of Environmental Justice in distribution planning over time, ensuring that the most vulnerable communities continue to see improvements. The Company will proactively monitor the progress of the ongoing and planned work in the EJ communities for reliability improvements and continue collaborating with customers and other stakeholders. Additionally, DTEE is joining forces with the MPSC and other stakeholders on potential Infrastructure Investment and Jobs Act (IIJA) grant opportunities to fund infrastructure-related programs to benefit vulnerable communities in alignment with the Biden

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Administration's Justice40 initiative.⁵³ The Company's current efforts to secure IIJA grants are further described in Section 16.

12.3 Tying Investments to Performance

Given the increase in capital investment needed to meet its grid performance goals, the Company acknowledges that stakeholders broadly desire greater utility accountability and a closer linkage between investments and performance. Specifically, the Company has identified two specific areas where utility accountability could be increased:

- In executing capital investments consistent with established plans and Commission orders
- To deliver targeted performance related to improved safety, reliability, and resiliency, while also preparing for a future that has increased Electric Vehicles (EVs), Distributed Generation / Distributed Storage, and other Distributed Energy Resources (DER)

The Company highlights that two efforts are underway, outside of this DGP filing, that have the objective of increasing utility accountability in these two areas. These are described in greater detail in the following sections, but at a high level those two efforts are:

- Performance Based Ratemaking (PBR) – In its April 24, 2023, Order in Case No. U-21400 (April 2023 Order), the Commission launched a “Financial Incentives and Disincentives” workgroup to explore the application of PBR and the appropriate use of financial penalties and rewards, and subsequently issued an order seeking comments on a PBR straw proposal for utilities.
- Infrastructure Recovery Mechanism (IRM) – In pending Case No. U-21297, the Company has proposed an IRM covering a portion of its strategic distribution capital investment; among other things, the proposed IRM would help ensure the Company makes investments consistent with its capital plans deemed prudent by the Commission.

⁵³ The White House, Justice40: A Whole-of-Government Initiative, available at: [Justice40 Initiative | Environmental Justice | The White House](#), accessed January 14, 2023.

Michigan Public Service Commission
DTE Electric Company
2023 Distribution Grid Plan U-20147

12.3.1 Performance Based Ratemaking (PBR)

The Company defines PBR as an approach to utility regulation that creates a stronger connection between a utility's financial outcomes and its performance. By more closely linking financial outcomes with performance outcomes, a utility is more strongly incentivized to achieve targeted performance.

The Company maintains its position that it remains open to PBR, potentially including the use of financial penalties and rewards tied to performance. However, given the recent guidance provided by the Commission discussed below, the Company has not included a specific PBR proposal in this DGP.

While PBR has been a topic of discussion within the State of Michigan since at least 2016, it was directly linked to the Company's Distribution Grid Plan (DGP) through the Commission's May 8, 2020 Order in Case No. U-20561 when the Commission directed:

"As part of its distribution investment and maintenance plan to be filed in 2021 in Case No. U-20147, the Commission directs DTE Electric to include proposed PBR elements with reasonable metrics tied to utility financial performance, improvement targets, and timelines for achievement." (page 106)

In that order, the Commission provided additional guidance on what the Company should consider when preparing its PBR proposal.

In compliance with the May 2020 Order, the Company filed its "2021 Distribution Grid Plan Final Report" (Case No. U-20147) on September 30, 2021. This filing included a discussion on PBR. More specifically, the Company proposed two near-term actions:

- The submission of a new standalone annual PBR report that would include new distribution performance metrics and expanded context and discussion of metric performance.
- The establishment of financial incentives and penalties associated with two reliability metrics.⁵⁴

⁵⁴ The Company noted in the 2021 DGP that "actual implementation of reliability metrics with financial incentives would follow an Order in a contested case subsequent to this case. Thus, it is expected that the metrics, targets, triggers and

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

In its July 1, 2022 filing in Case No. U-20147 (July 2022 Filing) the Company communicated its intent to suspend the filing of its proposed annual PBR report, citing in part a lack of Commission guidance on the Company's proposed PBR construct at the time and a desire for opportunities to "...further engage the Commission, Staff and interested stakeholders around its PBR proposal..." (page 2).

In its September 8, 2022 Order in Case No. U-20147 (September 2022 Order), the Commission provided the following guidance in response to the Company's and other utilities' PBR proposals contained within their respective distribution investment plans:

...the Commission finds what was submitted by the utilities in their distribution plans to be insufficient to address the issue of financial incentives and penalties at this time. (MPSC 2022, 71)

Subsequently, through its April 24, 2023 Order in Case No. U-21400, the Commission launched a "Financial Incentives and Disincentives" workgroup. Notably, the Commission provided the following guidance related to the focus of the workgroup in that order:

... an initial focus of the Financial Incentives and Disincentives workgroup shall include developing appropriate metrics relating to reliability including, but not limited to, SAIDI (including and excluding MEDs), SAIFI, CEMI, CAIDI, and resilience, including, but not limited to, downed wire response and the frequency and duration of outages during extreme weather, and shall use the recently updated Service Quality rules as a baseline. (MPSC 2023, 12)

and

"Beyond this primary focus on distribution reliability and safety, the workgroup shall also consider challenges around the readiness of utility distribution grids to effectively accommodate and leverage the increasing and further anticipated growth of distributed generation, EVs, and other DERs." (12)

and

maximum amounts, as well as the accounting treatment, would be addressed through a specific proposal by DTEE in a contested case prior to implementation."

“After developing metrics around distribution performance, the workgroup shall explore rate structures and the methods by which incentives and disincentives may be applied.” (12)

In a subsequent order issued on August 30, 2023, in that case, the Commission released its PBR “straw proposal” and sought comments from interested stakeholders. The Company provided its comments on September 22, 2023, and continues to be fully engaged in the workgroup.

12.3.2 Infrastructure Recovery Mechanism (IRM)

The Company defines an IRM as a regulatory tool that (1) provides customer protections in the event of utility underinvestment, and (2) allows a utility to recover the costs associated with certain capital investments made on behalf of its customers between rate cases. IRMs typically have a clearly defined duration, size, and scope such that the utility is limited to specific investments it can make under an IRM.

In pending Case No. U-21297, the Company has proposed an IRM focused on strategic distribution capital investments critical to customer safety, reliability, and resiliency. As discussed by Company Witness Foley in pending Case No. U-21297, the Company defined three main objectives of its proposed IRM:

“...the Company seeks to achieve the following through its proposed Distribution IRM:

- Increased accountability for the Company to fully execute its strategic investments critical to customer safety, reliability and resiliency deemed appropriate by the Commission;
- Increased transparency into the Company’s investment plans and timelines, and the execution of those plans, beyond the projected test year typically assessed during a general rate case; and
- Increased opportunities for Michigan Public Service Commission Staff (Staff) to review and provide input on the Company’s distribution investment plans.” (Foley direct testimony; 7)

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Importantly, under the Company's proposed IRM, any underinvestment by the Company would result in a return to customers. In this way the Company would be held accountable for making investments consistent with the Commission's approval of the IRM.

While a Commission order related to the IRM is forthcoming, the Company believes that both IRMs and PBR can be constructive tools to increase accountability for the Company to execute its planned capital investments and deliver on the performance improvements it is targeting through those investments.

13 Executing the Distribution Grid Plan



The scope and scale of the DGP will require significant effort and focus from DTEE to consistently achieve the targets laid out in this document. It will take expertise in engineering, procurement, project management, and construction. DTEE has anticipated these challenges and has been taking steps to address them.

13.1 Project Management Organization

As the scale of investment in the electrical grid has increased over the past several years, DTEE has taken steps along the way to grow its capital execution capabilities. Those increasing capabilities have delivered an improvement in strategic capital execution, including investing over \$350M into strategic capital investment programs in 2021, investing a record amount of strategic capital in 2022 of \$720M and a 2023 forecast exceeding \$800M.

The most recent step in the growth of organizational capabilities occurred in the summer of 2023, when DTEE merged the Major Enterprise Projects organization with the Distribution Operations Projects team to form the Project Management Organization, a team solely focused on the execution of strategic investment programs.

This balanced organization is formed around the investment pillars to support grid voltage conversion work: subtransmission system rebuilds, PTMM, 4.8kv hardening, and all other critical investment work. The organization also contains the necessary support resources to execute the growing levels of project work, including planning & coordination functions, controls and standards.

13.2 Workforce Planning

DTEE uses an integrated planning approach, taking into consideration work planned in the Distribution Grid plan as well as work identified in the annual capital planning cycle. These inputs are fed into a workforce planning model that provides annual resource demand for the next 10 years. The model breaks down projects into the labor resources required to execute the work, including frontline labor such as linemen, splicers and substation journeymen, as well as engineers, designers and project managers.

These forecasts are then used to aid the organization in key decision making to help fill those demands. Some of the workforce will be hired and trained as full-time employees through the Department of Labor certified apprenticeship programs for linemen, splicers, substation maintenance journeymen and planners (designers).

DTEE also works closely with the International Brotherhood of Electrical workers (IBEW) and the National Electrical Contractors Association (NECA) to support the training of new apprentices through their joint training program with the American Line Builders Apprenticeship Training committee. This collaboration trains future workforce for all manner of distribution electrical work including overhead lines, cable splicing, substations and URD. Through these joint training efforts, DTEE has been able to increase the size of its on-property contract workforce by over 25% since the beginning of 2022. DTEE is also hiring a growing number of engineers, project managers, and technicians to support the increasing workload. While DTEE hires experienced employees, it also brings in interns or co-ops and provides them with significant on the job training and coaching throughout their time with the Company. These employees often go on to take full-time roles within the Company or return to DTEE later in their careers.

DTEE has also grown its partnerships with several engineering and design firms, with significant portions of the detailed design work now being completed by these firms. These partnerships have led to several contracting models being utilized to complete work, including the use of Owner's Engineer and EPC (engineer-procure-construct). The work in the last two years has increased overall capacity, as well as expanded understanding of how to grow to the scale of the execution portfolio. DTEE envisions bidding multi-year master service agreements for EPC type work in the areas of "repeatable" investments, such as subtransmission rebuilds, URD replacement, and 4.8kV conversions.

13.3 Material and Equipment Planning

With the establishment of the new PMO organization, DTEE is expanding its material forecasting model. The DGP and annual capital planning processes are used to build forecasts for all key equipment necessary to execute grid plans – everything from poles, wires, and line hardware to substation transformers, and smart grid equipment.

DTEE has developed longer-term agreements with two key suppliers for the supply of line hardware materials (crossarms, insulators, wire, etc.). To support these agreements, vendors are taking specific steps to increase their capacity. The material forecasting model has also allowed negotiation of guaranteed production slots for key long lead equipment.

The capital investments outlined in this distribution grid plan make it essential to evolve DTEE's procurement and supply chain practices. The difficulty of securing materials due to nationwide shortages over the past few years further emphasizes the need for flexible and resilient strategies. The Company will stabilize and expand supply chain capabilities and improve inventory management.

- **Expanding supply chain capabilities:** Increasing resources in procurement and warehousing will enable efficient sourcing and storage of materials and equipment. In addition, a dedicated Quality Management Department is in development that will ensure rigorous assessment and control of vendors and materials. Key objectives of this department include:
 - Assessing current and potential vendors: evaluate existing and potential vendors of engineered materials to ensure reliability and quality

- Supplier Quality Manual (SQM) development: Develop an SQM to establish clear quality expectations and standards for suppliers
 - Expanding quality audits: Regular quality audits will verify compliance with established standards
- **Improving inventory management:** For long lead time items critical to project success, negotiations will take place with key suppliers to secure guaranteed production slots. Strategic and tactical forecasting demand meetings will take place to track spending patterns and plan inventory accordingly. To minimize lead time risk and mitigate inflationary pressures, the Company will proactively procure materials for future years.

Conclusion

DTEE's focused efforts on improving the execution of its capital programs have driven significant results in the last two years. The additional work in the creation of the PMO, workforce planning, and material planning provide a secure path to deliver on the increasing demands for upgrades to the electrical grid in the coming years.

14 Storm Response



14.1 Mutual Assistance

DTEE understands that losing power for any reason is difficult for customers, especially at times of adverse weather when there is a high volume of outages and restoration may take longer. Storms that cause outages typically have high winds, but rain, icing, and other factors can also have significant impact on the electric grid. To prepare for these instances, DTEE has a robust and comprehensive process that normally starts 48-hours ahead of expected weather impact and continues until the final customer has been restored.

DTEE is constantly monitoring weather and watching storms evolve. When a storm or other weather event is predicted, and even before the weather impact, DTEE performs scenario planning around the predicted weather, its potential outage impact on customers, and restoration duration. This analysis, led by the Incident Commander, Operations Chief, and Mutual Assistance (MA) Manager, gauges the local availability of restoration resources and allows for the strategic prestaging of additional outside labor resources, if needed, ahead of the weather. This strategy, learned from benchmarking of other utilities impacted by hurricane recovery, can reduce customer restoration time.

After DTEE's service territory has been impacted by the predicted weather system, the MA Manager again coordinates with the Operations Chief to gather initial reports from the field about the extent and location of damage to feed into the development of the Planning Scenario and Mutual Assistance Resource Plan. The Operations Chief, Logistics Chief, and MA Manager utilize

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

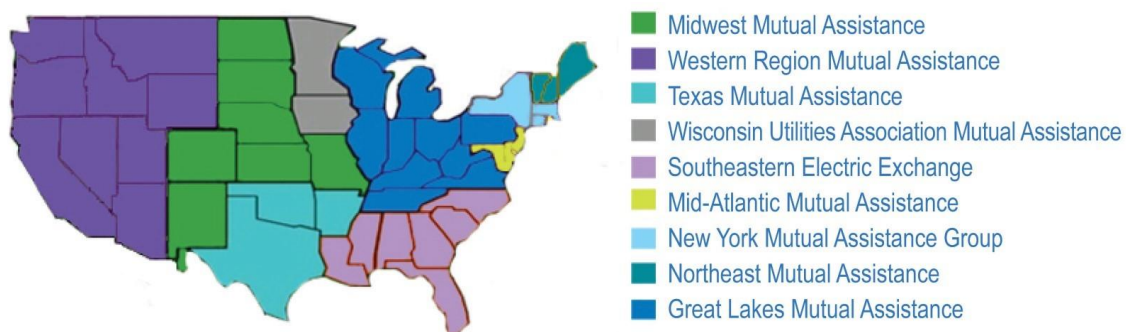
this information to make a recommendation to the Incident Commander detailing the number and type of additional mutual assistance crews that should be requested.

Once the need for additional crews has been identified, DTEE has two options for engaging these resource pools.

1. Traditional Foreign Crews Through Mutual Assistance

DTEE is a member of Great Lakes Mutual Assistance (GLMA) program as part of the Midwest Regional Mutual Assistance Group (RMAG). GLMA group members are neighboring utilities around the Great Lakes area that are signatories to the EEI Mutual Aid Agreement. Once the need for foreign resources is established, a call will be conducted with all member utilities to discuss crew needs and availability across the entire region. Member utilities can choose to either release or hold their restoration resources depending on the expected weather or damage in their specific service territory. Most often this is a reactionary exercise that follows the known impact of the weather; utilities very often hold their resources until the local impact is fully understood. Once released, the restoration crews will travel to southeast Michigan to begin restoration efforts. Should there be not enough crews to meet the demand, DTEE will engage other Regional Mutual Assistance Groups (RMAG) in the United States and Canada. A map of the mutual assistance groups within the United States is shown in Exhibit 14.1.1.

Exhibit 14.1.1 Mutual Assistance Groups within the United States



Map showing the seven mutual assistance group regions in the system of sharing resources to restore power in the U.S. Michigan is in the Great Lakes region.
Edison Energy Institute

2. Non-Traditional Foreign Resources

Starting ahead of the 2020 Storm Season, DTEE began to investigate alternatives for acquiring foreign crews to assist with storm restoration. To support this goal to expand restoration resources, DTEE identified contractors within the Midwest that are not tied directly to GLMA utilities. These

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

contractors can move quickly and do not require permission from parent/host utilities before they're allowed to send crews to our service territory for assistance with customer restoration. These contract crews can be in DTEE's service territory typically anywhere from 4 – 12 hours from the time of the request and will stay until they are no longer needed.

In addition to these resources, DTEE has entered into contractual agreements with many Michigan-based electric utility contractors that do not perform work on DTEE's property day-to-day. These "Local Foreign" contractors make up to approximately 200 additional restoration resources that can be quickly mobilized to support customer restoration.

Additionally, DTEE has retained a Michigan based multi-state lineman company in a Right of First Refusal contract giving DTEE access to over 200 line workers before any other utility in the country. Between the non-utility-based contractors, Local Foreign, and the Right of First Refusal crews, DTEE is positioned to bring in, and have working, up to 500 crews (1800 FTEs) within 12-16 hours of a weather event.

14.2 Wire Down Response

DTEE has a robust wire down it employs in response to downed wires that utilizes technology, people, and process as discussed below.

Technology

DTEE has developed several technology tools to help quickly mitigate downed wires that could threaten the public following a weather event. DTEE has developed an internal auto-dispatching tool (Chatbot) to speed up the response time of Public Protection resources to locations of reported wire down. The tool directly dispatches the closest available member of the Public Protection Program to the location of the highest priority wire down. Since the Company is working to address reported wire downs from the public, the wire could be an actual electric wire down, a joint use cable such as telecom, or in some cases no wire or cable is actually down.

Once the Public Protection team has arrived and confirmed that an electric wire is down, the Chatbot will take them through a list of questions that prompt them to tape/secure the site and report any information that will be pertinent to the line crews who follow. After completing these questions and securing the hazard, the Public Protection crew will text the Chatbot to receive their dispatch orders for the next closest, highest priority, wire-down event. The implementation of this

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Chatbot has improved the dispatch time of Public Protection resources since its implementation in 2021.

People

To support the Public Protection Program, DTE Electric has engaged the entire DTE Energy employee team to recruit, train, and equip more storm resources for securing downed wires, and other storm process roles. Every member of the Public Protection team receives extensive training including mentored storm work. Once graduated from the training program, a Public Protection team member will be able to safely and effectively secure downed wires in the field, making the grid safer for the public. DTEE has successfully trained over 500 non-DO resources from throughout the entire DTE Energy enterprise to support this initiative.

Process

The Public Protection Program helps to make wire down events safer by taping off and securing the hazard to help the public avoid dangerous areas. To perform this function, public protection team members require consumable equipment that can run out in the middle of performing this function. Starting in 2023 DTEE has deployed materials to local warehouses and locations across the entire service territory. This helps to respond to wire down events more quickly by allowing support teams that start from across southeast Michigan to resupply more easily.

14.3 Singles Damage Assessment

After the 2021 Storm Season, DTEE started a new Damage Assessment program to speed up the restoration of small and single customer outages, which in most cases are repaired at the tail end of storm restoration. Key to this strategy is targeting small customer outages (typically fewer than 10 customers reported out of power along an entire distribution circuit) for assessment earlier in the restoration process. This program, Singles Damage Assessment (SDA) is a best-in-class program that has been shown to improve the restoration speed of small outages by approximately 14%. Once DTEE has entered Storm Response, SDA will be activated to begin the assessment and preflight of any single customer outage or any outage that is below the level of a transformer device, typically fewer than 10 customers.

The entire circuit patrol is not normally required to resolve these smaller outages, so teams are dispatched directly to the location of the reported trouble. After the SDA team arrives at the location, they will assess the outage conditions, identify resources and materials required, alert

the nearby customers of any safety concerns and secure any downed wires. DTEE has access to additional non-lineman resources that can assist with this type of restoration, depending on the degree and location of damage. By better assessing the damage up front, DTEE can identify the correct resources earlier, and perform customer restoration more quickly. When DTEE can perform restoration without an Overhead Lines Crew, not only can the customer be restored more quickly but the linemen can be allocated to other jobs that do require their specific skillset.

The SDA program also helps to identify Ok-On-Arrival sites where the reported hazard causing the outage has been cleared or problem may have existed for only a moment. When a weather event comes through the service territory, overhead wires can contact trees, animals (birds and squirrels), and other wires. While these hazards can cause flickering lights or outages, over a multiple day restoration effort, they sometimes can clear themselves without any actual restoration work.

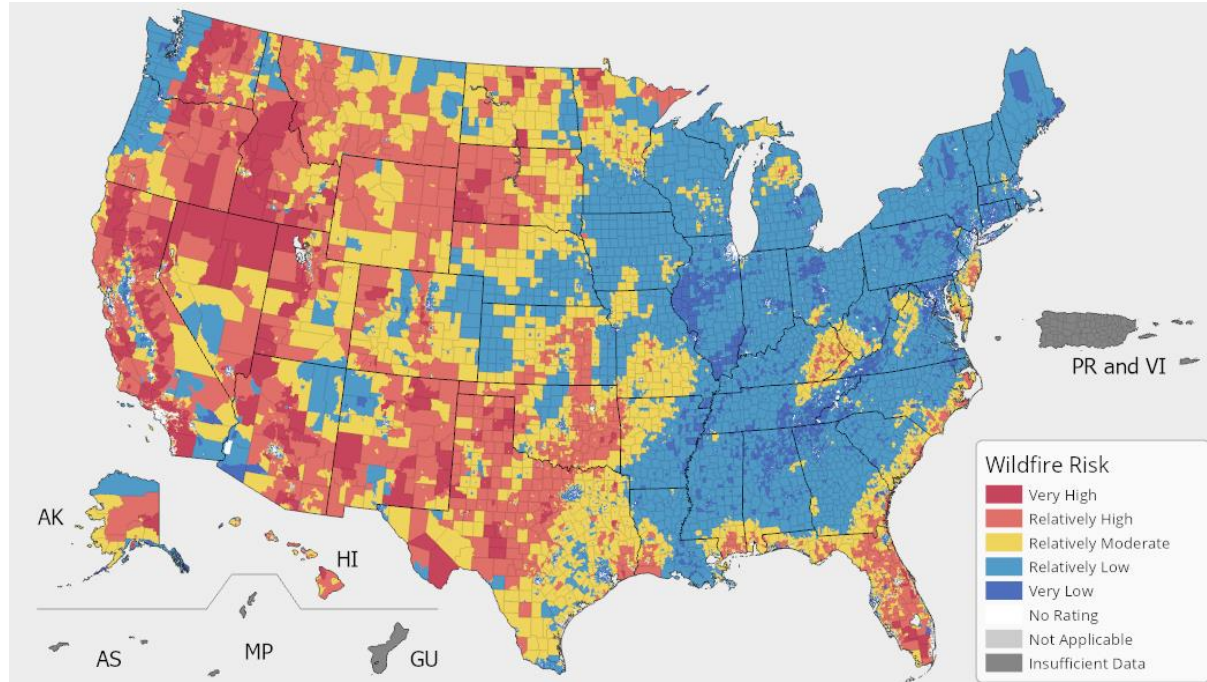
SDA helps to identify these locations where power has already been automatically restored or temporary problems cleared, and DTEE will not need to send an additional restoration resource to the site. By reducing and pre-flighting these Ok-On-Arrival events, the overall storm restoration process is more efficient, and DTEE can better allocate their resources to the sustained outages that require them.

14.4 Wildfire Mitigation Approach

The risk for wildfires exists in Southeast Michigan but is significantly lower than other parts of the country. While Michigan has experienced a few wildfires in recent years, nearly all of them have occurred in Northern Lower Michigan and the Upper Peninsula.

The graphic below published by Federal Emergency Management Agency (FEMA)⁵⁵ shows that the DTE Electric service area is classified as being at *Relatively Low* or *Very Low* Wildfire Risk. These are the two lowest risk categories.

⁵⁵ Wildfire risk map by Federal Emergency Management Agency (FEMA) - [Wildfire | National Risk Index \(fema.gov\)](https://www.fema.gov/wildfire-risk), accessed September 23, 2023



While the wildfire risk in DTEE's service territory is low, many of the Company's planned investments in the distribution system and its storm response processes described above are intended to mitigate risks posed by downed wires, including fires. Specifically, PTMM, 4.8kV Hardening, 4.8kV conversion, and tree trimming will all prevent downed wires. Additionally, the installation of viper reclosers in the grid automation program described in section 10.1, is intended to decrease the risk of adverse impact from downed wires.

Additionally, the DTEE System Operations Center (SOC) has established real time processes that enable the control room to take quick action to de-energize DTE Electric equipment during emergent field conditions. This de-energization is accomplished either remotely via the SCADA control system, or through field resource actions when the emergent information is conveyed to the SOC control room.

14.5 Storm Estimates and Power Status

In addition to concerns about outage frequency and duration, customer feedback on outages has increasingly focused on DTEE's need to improve the timely and accurate communication on their outage status and restoration estimate. The Error Free Communication (EFC) program is designed to ensure that customers experience quality communication throughout the duration of

an outage. Feedback indicates that customers want to better understand their outage, including a clear and correct estimate of restoration, as well as the cause of the outage. Customers also want to have confidence in their restoration notice, knowing that when DTEE informs them the power is back on the outage is truly over.

Several factors contribute to the Company's ability to provide a quality communications experience for customers during an outage. Timely and accurate communication with meters at customer locations, resilient backend systems that use data to determine the power status at a residence (Outage Management System [OMS], Customer Management System [CRM]), and systems that communicate with customers must all work seamlessly in concert to support consumers notifications. DTEE is making investments in its Automated Metering Infrastructure (AMI) system that specifically improve the quality and timeliness of collecting and utilizing the AMI data. The greater the volume and quality of the data collected, the better the system(s) will perform, and this expanded pool of data will allow DTEE to better model outage events within the OMS, delivering a more accurate prediction of outage magnitude (cause, size, extent of damage). Accurate prediction is key to restoring power as safely and quickly as possible, including initiating and maintaining communications with customers about their event.

DTEE made significant progress this year in improving the resilience of its digital communication. In past storms, customers and communities have reported issues with being able to consistently reach DTEE. In response the Company made aggressive corrections, and in the most recent weather events all systems performed well.

The EFC program continues to improve the accuracy and timeliness of outage communications. Timely, accurate restoration estimates for customers remain a significant area of focus. While estimate accuracy still needs to be improved, DTEE is investing in additional communication technologies to improve its score, rigorously testing improvements and measuring efficacy to ensure better communication with customers during outages.

15 Base Capital



Base capital refers to the investments associated with work activities that DTEE performs as part of the normal business of serving our customers. These activities include restoration of customers after a storm or equipment failure, connection of new customers, and the relocation of existing assets.

Base capital is divided into two major categories: 1) emergent replacements, and 2) connections, relocations, and other.

15.1 Emergent Replacements

Emergent replacements are those necessitated by damage or failure on the system and are reactive, rather than proactive, but nonetheless essential to maintain safety and reliable operation of the system. There are three types of emergent expenditures: Storm, Non-Storm, and Substation Reactive.

15.1.1 Emergent Replacement – Storm

This category includes investments required to perform repairs of the overhead and underground distribution and subtransmission systems for damage which occurs during storms. Expenditures are made to replace damaged equipment which caused power outages our customers or created a hazard. DTEE defines a storm as 760 outages events affecting at least 200 circuits. Equipment examples include poles, crossarms, and conductors, among other assets.

15.1.2 Emergent Replacement – Non-Storm

This category includes investments required to perform repairs of the overhead and underground distribution and subtransmission systems for damage during non-storm conditions. The “non-storm” description does not imply that these events are not caused by whether such as thunderstorms and high winds. It simply means that there were not enough outages for “storm” conditions to be declared, as defined in Section 16.1.1. Failures in the non-storm category can also include failures from public interference, age-related equipment failures and more. Equipment examples include poles, crossarms and conductors, among other assets.

15.1.3 Emergent Replacement – Substation Reactive

This category includes investments required to perform emergency replacement work for substation equipment. DTEE makes these expenditures to replace broken or failed equipment that either led to customer outages, created a risk of customer outages, created a hazard, or impacted the operability of the electrical system. Equipment examples include breakers, substation transformers, and substation reclosers. Additionally, substation reactive includes expenditures made to non-electrical equipment necessary to operate the substation, maintain security, and reduce hazards. An examples of non-electrical substation reactive expenditures include fence/gate repairs mandated by NERC security protocol and replacing HVAC heating to remove condensation to mitigate equipment corrosion.

Exhibit 15.1.3.1 Emergent Replacements Investment (\$ Millions)

Category	2024	2025	2026	2027	2028	5-Year Total
Emergent Replacements	\$415	\$399	\$368	\$348	\$345	\$1,877

15.2 Connections, Relocations and Other

The connections, relocations and other investment category is further broken down in to five major sub-categories: Connections and New Load; Relocations; Electric System Equipment; NRUC and

Improvement Blankets and General Plant, Tools & Equipment and Miscellaneous. Exhibit 15.2.1 provides the connections, relocations and other investment for 2024-2028

Exhibit 15.2.1 Connections, Relocations and Other Investment (\$ Millions)

Category	2024	2025	2026	2027	2028	5-Year Total
Connections, Relocations and Other	\$282	\$295	\$314	\$334	\$355	\$1,580

15.2.1 Connection and New Load

The Connections and New Load sub-category investments are divided into two categories: Small Load Growth projects & Customer Connections, and New Business projects.

Small Load Growth & Customer Connections projects are projects required to serve new load, customer connections, or an upgrade needed to address a limited level of loading issues on the electric system. Projects in this category are typically less than \$500,000 to complete and are developed and executed by distribution regional service centers. Activities to support these customer needs may include reconductoring lines, minor expansions to a substation, or transferring load to provide load relief. Other typical projects in this sub-category include installing additional overhead and underground lines to provide service to small commercial businesses or housing developments. Small Load Growth & Customer Connections projects are often requested by customers and can carry a customer contribution in aid of construction (CIAC) cost wherein the customer pays an allocated cost of new service depending on the requested load and service requirements.

New Business investment projects are larger customer-driven projects, more than \$500,000, and require a central engineering approach to design and implementation. Like Small Load Growth and Customer Connections, these are projects required to serve new load, connections or to address loading issues, but are on a larger scale. Activities to support customer new business needs often include installing additional overhead and underground lines or upgrading or building new substations to provide services to large commercial or industrial customers. As with Customer Connections, New Business projects are often requested by customers and can include a CIAC cost, where the customer may be responsible for an allocated cost of system upgrades,

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

depending on the existing system conditions, the requested load, and the impact to the electrical system.

These investments connect new customers, support area load growth for both existing and new customers, enable economic growth, and ultimately support customers.

15.2.2 Relocation

Relocation projects are requests from customers or municipalities and other governmental entities, including the Michigan Department of Transportation, to relocate existing DTEE facilities. These requests are typically related to construction activities in specific geographic areas, including the modification of roadways, bridges, water mains, public sanitation, alleys or other customer activities.

DTEE facilities being relocated could include overhead lines and poles, or underground lines and pad-mount transformers, or possibly substations and system cable. With expected federal investment driving investments in municipal infrastructure, it's expected that these types of projects will become more frequent in the coming decade.

These investments can enable economic growth, meet customer needs, are required by regulation, or at the request of municipalities. Similar to Customer Connections and New Business, some projects requested by customers or municipalities include a CIAC cost wherein the requester pays for part of the costs of relocating DTEE assets.

15.2.3 Electric System Equipment

DTEE maintains an inventory of critical spare equipment in order to support both emergent replacements and planned projects. The Electric System Equipment sub-category of investment includes investments in equipment, particularly long lead time items, to provide proper inventory levels of major electric system equipment. Equipment purchased under this sub-category includes substation transformers, distribution transformers, regulators, and meters, among other items.

These investments provide inventory to help serve customer needs in a timely fashion, so that urgent work is not slowed down due to a need for critical equipment.

15.2.4 NRUC and Improvement Blankets

There are three subcategories that make up the NRUC and Improvement Blankets: (1) System Improvements, (2) Normal Retirement Unit Change-out (NRUC), and (3) Operation Technologies.

System Improvement projects are small projects managed by regional operations to immediately address customer issues, reliability, and complaints. These are projects that do not require extended planning and design and do not exceed \$350,000.

NRUC consists of projects to perform scheduled work that replaces assets (pole top switches, reclosers, capacitors, and regulators) determined to be end-of-life. These assets are inspected by overhead linemen or power quality technicians to determine if they are end-of-life.

Operational Technologies consists of the infrastructure and associated applications that support the AMI platform and data. This also covers annual work in testing new meter types, designing and installing configurations, replacing communications equipment, and testing changes for new equipment.

15.2.5 General Plant, Tools & Equipment, and Miscellaneous

General Plant, Tools & Equipment and Miscellaneous includes the tools and replacement tools required for linemen and splicers to perform their work, and test equipment used by engineers and technicians. In addition, this sub-category includes substation physical security investments.

These expenditures ensure that DTEE work crews are equipped for their day-to-day field work. Examples of items included in General Plant, Tools & Equipment and Miscellaneous include: very low frequency (VLF) trucks used to test cables at frequencies between 0.02 and 0.1 Hz, DC hi-potential testers (Hippoters) used to test insulation on cable, breakers, transformers, etc., oil processing trailers, insulated screwdrivers, pencil tip soldering iron and other tools and equipment.

15.2.6 Other Known Major Projects

DTEE supports some grid work that is outside of the more typical categories already described in this plan. The Blue Water Bridge Plaza expansion project is a large relocation project example where DTEE is leveraging the required relocation project to begin the 4.8kV to 13.2kV conversion effort in the Port Huron area.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

To build the new Blue Water Bridge customs plaza, the Michigan Department of Transportation (MDOT) requested that DTEE relocate all its facilities outside the expanded plaza footprint. This requires construction of a new electrical substation ('Neon') to replace the existing substation ('Pinegrove') which resides in the future plaza footprint. The new substation will be built to current 13.2kV standards, replacing the existing 4.8kV site, fulfilling the needs of the relocation while delivering increased reliability and capacity to our customers. DTEE agreed to a joint venture with MDOT wherein MDOT would pay a portion of the cost to relocate DTEE facilities. The project is expected to be completed by the end of 2026.

15.2.7 Transportation Electrification Plan

After four years of executing on its EV pilots under the Charging Forward umbrella, DTEE is transitioning to longer-term programming by developing a comprehensive Transportation Electrification Plan (TEP) that will detail its EV strategy, programs, and investment through 2028 and be published by year end. DTEE forecasts over 300,000 EVs in its service territory by 2028 up from nearly 40,000 today. To support this level of EV adoption, approximately 270,000 additional chargers are needed in single family homes, multi-unit dwellings, fleet depots, workplaces and public areas between through 2028.⁵⁶

Although the final TEP is still in development, regardless of what incentives for charger deployment are ultimately proposed and approved, customers will request new or upgraded service connections from DTEE to install the additional chargers. Based on historical work order analysis and cost data from Roland Berger's global database, approximately \$189 million of distribution investment will be needed on the utility side of the meter to connect the chargers required to support EV adoption through 2028. From this same analysis, DTEE estimates that it will be responsible for approximately 85% of that investment cost, and the balance will come from customers' contribution in aid of construction (CIAC). Therefore, the total DTEE portion of the required distribution investment, \$161 million, has been included in the new customer connection portion of the budget.

⁵⁶ A detailed study was performed leveraging Roland Berger and their global EV database and automotive experience. The model output is based on assumptions for the number of vehicles served by each charger in a segment (e.g., from one EV for a single-family home to 200 EVs for a public fast charger) as well as the power levels (e.g., 12-150 kilowatts).

16 IIJA Distribution Grid Activity



On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act or Bipartisan Infrastructure Law (the “IIJA” or the “BIL”), a once-in-a-generation opportunity to invest in the Nation's infrastructure, competitiveness, and communities.

Over the past year and a half, DTE has applied for IIJA grants as well as analyzed, performed outreach, and supported third party applicants. DTE has applied for three grants and plans to apply for an upcoming request for proposal in grid resilience and innovation areas to bring additional investment into Michigan.

1. Smart Grid Grants (40107)

On March 17, 2023, DTE filed for a \$23M grant for a project to construct two sets of adaptive networked microgrids to Grid Resilience and Innovation Partnerships (GRIP) topic area 2 grant. These microgrids will be networked to increase flexibility and reduce the number of outages for area residents. As of mid-September 2023, DTE has yet to be notified on the award of the grant.

2. Grid Resilience Grants (40101c)

On April 6, 2023, DTE filed for a \$100M grant to GRIP topic area 1 for a project to: (1) expand an existing substation by adding a third 13.2kV transformer and converting the 4.8kV equipment to operate at 13.2kV, (2) rebuild 145 miles of 4.8kV overhead distribution circuits, (3) decommission

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

two other substations by transferring their load to the newly expanded substation, and (4) install an EV Charging. As of mid-September 2023, DTE has yet to be notified on the award of the grant.

3. Grid Innovation Program (40103b)

On May 19, 2023, EGLE proposed an innovative large-scale public-private partnership to implement a shared remote sensing solution that leverages light detection and ranging (LiDAR) to create a geospatial “digital twin” of Michigan’s geography. DTE is a subrecipient and financial partner to the application. As of mid-September 2023, EGLE has yet to be notified on the award of the grant.

4. Resilience for States & Tribes (40101d)

In May 2023, the EGLE submitted a \$14.9M application for Preventing Outages and Enhancing the Resilience of the Electric Grid. EGLE was awarded on July 6, 2023. Next, EGLE will issue a Request for Proposal (RFP) for eligible entities to apply for a portion of the funding. The Company looks forward to the release of the State’s RFP and submitting an application that best aligns to the program scope and budget.

16.1 Actions and On-going Activities

DTEE will continue to actively pursue applicable grant opportunities that benefit its customers, support the Company’s decarbonization objectives, improve the distribution grid reliability and resiliency, and support the state’s progress towards meeting its climate goals. Progress is shared biannually in MPSC Case U-21227.⁵⁷

⁵⁷ [Case: U-21227 \(site.com\)](#)

Michigan Public Service Commission
DTE Electric Company
2023 Distribution Grid Plan U-20147
17 Stakeholder Engagement



DTEE has ongoing outreach and regular engagement with customers and stakeholders that includes issues related to the distribution grid to both communicate updates and listen to feedback. For example, the Company sends out a newsletter to elected officials, local leaders and community partners to provide critical information during severe weather events and works with municipalities and customers to communicate upcoming infrastructure projects happening in their communities. In addition to these regular efforts, DTEE conducts targeted initiatives in alignment with the Company's DGP and other regulatory filings with the MPSC. For example, in preparation for the Company's last DGP in 2021, DTEE conducted research with customers and other stakeholders to receive direct feedback about their perceptions of the Company and how they feel about the electric reliability they receive. DTEE also received comments from customers on issues related to the distribution grid through the Voice of the Customer research conducted in preparation of the 2022 Clean Vision Integrated Resource Plan. While this research was targeted to solicit feedback on electric generation issues, concerns were noted from participants regarding the duration of outages and inconsistency in reliability across DTE Electric's service territory.

In preparation for the 2023 DGP, DTEE built upon these prior initiatives and learnings to dive deeper and gain additional insights from customers, communities, and technical stakeholders. DTEE appreciates the feedback the Company has received, as well as the time various stakeholders took to provide their perspectives and views. The Company recognizes that distribution planning is an iterative process and looks forward to continuing to listen to customers

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

and other stakeholders and incorporating their sentiments into ongoing distribution planning efforts.

17.1 Customer Engagement

The Company is listening to the perspectives and concerns offered by customers through direct communication channels as well as external venues. This information from customers is an essential component of DTEE's distribution planning and communication processes. Through prior customer research, the Company learned that customers felt DTEE does not



aggressively maintain or upgrade its distribution grid because of a lack of visible upgrades and maintenance. Many residential customers suggested that DTEE regularly communicate to them with infrastructure updates that represent modernization/improved reliability in their immediate communities so they better understand what is taking place, even if they may not personally see the work happening. Based on this feedback, DTEE enhanced its customer communications by developing a reliability-focused Empowering MI blog site⁵⁸ and is sending out targeted emails to let customers know about distribution work happening in their area. In addition, DTEE has developed the Electric Reliability Improvements Map (Exhibits 14.1.1 and 14.1.2) to provide customers with information on near-term reliability improvement projects in the areas of tree trimming, strengthening power lines, utility poles maintenance, rapid response, and modernizing and rebuilding the grid.⁵⁹ The Map is available on the Company's website⁶⁰ and allows users to navigate through DTEE's entire service territory or search a specific address or place.

⁵⁸ <https://empoweringmichigan.com/category/your-neighborhood/reliability-work-updates/>

⁵⁹ Maps show investments and improvements the Company is making through 2023. Planned work boundaries are approximate and may not represent the exact extent of the work. Accessed August 16, 2023.

⁶⁰ <https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e#>

**Exhibit 17.1.1 Electric
Reliability Improvement Map
(DTE Service Territory)**

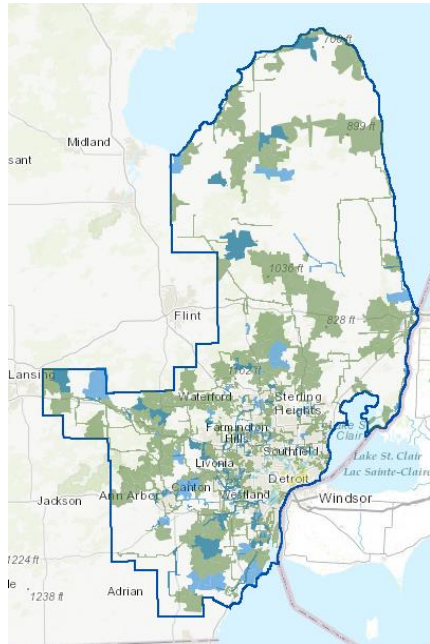
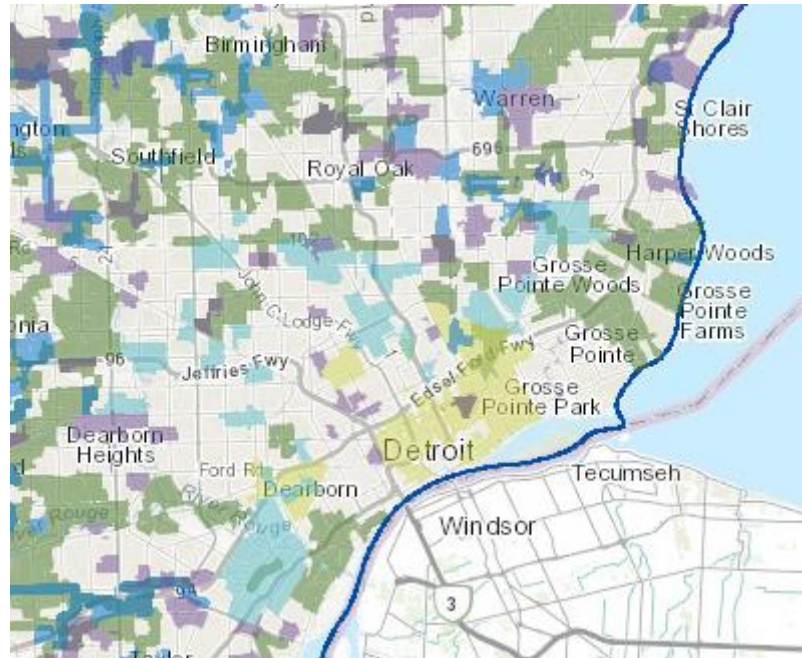


**Exhibit 17.1.2 Electric
Reliability Improvement Map
(Metro Detroit)**



	Tree Trimming	Tree limbs and branches are responsible for nearly 70% of the time our customers spend without power. That's why we're surging our efforts to trim overgrown trees in your neighborhood to keep you safe and the energy grid reliable.
	Strengthen Power Lines	We're upgrading and strengthening power lines to ensure the electric system in your neighborhood is more resilient and reliable.
	Utility Poles Maintenance	We're inspecting and repairing utility poles and replacing cross arms and other pole top equipment to ensure our system delivers the power you need when you need it.
	Rapid Response	Tree trimming and pole top equipment repairs/replacements to quickly improve reliability in communities experiencing emergent issues in between planned maintenance schedules.
	Modernizing & Rebuilding the Grid	Modernizing electrical substation equipment, as well as the underground and overhead infrastructure that delivers power to you, including replacing poles and wiring. Tree trimming will be completed, as necessary, in advance of pole replacements.

DTEE has also been listening to the concerns raised by customers at recent Legislative and Commission-led events. In March 2023, the MPSC held three townhalls to give Michiganders,

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

including DTEE customers, a chance to share directly with state regulators their experiences during and after the February and March 2023 ice storms. Key themes raised by attendees include:

- Frustration over frequency and duration of outages
- Dissatisfaction with electric rate increases
- Desire for clean energy resources, including rooftop solar
- Challenges reaching energy provider via phone and imprecise communications regarding outages/restoration efforts
- Discontent with outage credit compensation

Similar sentiment was shared at a June community event in Detroit as part of the Michigan House Energy Reliability, Resilience and Accountability Task Force's listening tour. In addition, DTEE also regularly tracks customer complaints submitted to the MPSC regarding the Company's distribution operations. Through August 2023, the highest number of distribution-related complaints were related to frequency and duration of outages, and restoration estimate times during an outage. DTEE works directly with customers to address these issues.

The Company understands the frustrations customers experience because of outages. The proven investments highlighted in this plan will reduce the number and duration of outages during these severe weather events. Additional information on how DTEE is addressing customer feedback from the February ice storms is in Appendix D.

Building on these key themes and findings from prior customer outreach, DTEE conducted additional research to better understand customers' awareness and attitudes toward the Company's distribution planning efforts. A third-party research company surveyed more than 4,300 residential customers throughout DTEE's service territory through an online questionnaire.

Through this research, the Company learned:

- Most respondents (55%) had seen or heard something pertaining to DTEE's efforts to improve the grid prior to taking the survey
- Most respondents (61%) preferred to receive updates on the plan via email; the DTE Energy website (39%) and bill inserts (35%) were also popular methods of communication

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

- Most respondents found all four key pillars of the DGP to be a high priority,⁶¹ and there was a particular interest in burying lines underground to improve reliability
- Respondents were sensitive to the plan's impact on increasing their electric bill⁶²
- Most respondents (52%) who contacted DTEE regarding an outage in the past six months rated the effectiveness of the complaint process as a 6 or lower (on a 0-10 scale)

Based on these research findings, the Company's enhanced customer communications appear to be a step in the right direction to increase customers' awareness of the work DTEE is doing to improve distribution reliability and resiliency. Customers agree that the four key pillars of focus and investment should be high priorities, and the Company should continue to balance the need for these significant investments with customer affordability. Finally, the Company knows it has more work to do to improve the quality of customer communications and resolution of complaints during outages.

17.2 Community Engagement

DTEE has heard from customers, community leaders and technical stakeholders that equity and environmental justice are important issues that should be considered in distribution planning. As outlined in Section 12 of this report, DTEE has taken several measures to incorporate this feedback. In addition, a key component of environmental justice is meaningful involvement. As such, the Company seeks to deepen its outreach and engagement with vulnerable communities leveraging the analysis of reliability performance in vulnerable communities (described in Section 12) to identify and target engagements with stakeholders in these vulnerable communities. During these discussions, the Company is informing community members of its planned distribution investments, how its distribution planning process is integrating equity and environmental justice and listening to better understand the communities' sentiments related to distribution issues.



⁶¹ Percentage of respondents that rated each pillar as a very high / high priority: rebuilding significant portions of the grid, 88%; upgrading existing electric distribution infrastructure, 83%; trimming trees, 73%; transitioning to a smart grid, 72%.

⁶² 47% of respondents reported their opinion of DTEE would be somewhat / much worse if their monthly electric bill increased by less than \$10 per month to cover the cost of the plan.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

In addition, the Company is continuously reaching out and listening to its communities through multiple channels, including regular meetings with federal, state and local representatives; meetings with community leaders from faith-based institutions, social service agencies, advocacy organizations and others who represent the DTEE customer base; community stakeholder surveys; and interactions with community members at District meetings in Detroit, informal neighborhood gatherings and DTEE Community Van deployments during storm recovery.

During these conversations, community members have been receptive to DTEE's four-point plan, and the variety of solutions being implemented. There is a desire to understand the reliability performance of the local community and how that compares to other communities. In addition, communities want to understand how the overarching investment programs identified in the DGP will translate into investment plans at the local level, when that investment is expected to take place, and the reliability improvements that can be expected after the plans have been implemented. DTEE looks forward to maintaining a dialogue with its communities and further understanding the communities' sentiments toward distribution issues. While DTEE reports reliability performance data with the MPSC on a quarterly basis,⁶³ the Company is developing ways to share this information with the community. In addition, to better address community members' desire for localized information about DTEE's investments, the Company is exploring enhanced ways to effectively communicate plans for improving reliability.

17.3 Technical Stakeholder Engagement

Technical stakeholders include parties that participated in the Company's 2021 DGP technical conferences or expressed interest in participating in the 2023 technical conferences by signing up for the MPSC's email distribution list. DTEE held two virtual technical conferences in preparation of this DGP. The first conference, held in March 2023, was focused on the 4.8kV electric distribution system and had over 200 participants. The second conference, held in August 2023, previewed key topics from the 2023 DGP with stakeholders and had over 180 participants. Both events were hosted and moderated



⁶³ <https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics>

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

by the MPSC and included a question-and-answer segment. The agendas, presentations, conference recordings and follow-up responses to questions are all available on the Commission's websites.^{64,65} In addition, DTEE developed a dedicated DGP email address to maintain regular engagement with technical stakeholders on distribution planning.

⁶⁴ <https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference>

⁶⁵ <https://www.michigan.gov/mpsc/commission/events/2023/08/31/dte-distribution-grid-plan-technical-conference>

Appendix A State of the Grid

Exhibit A.1 DTEE Distribution System

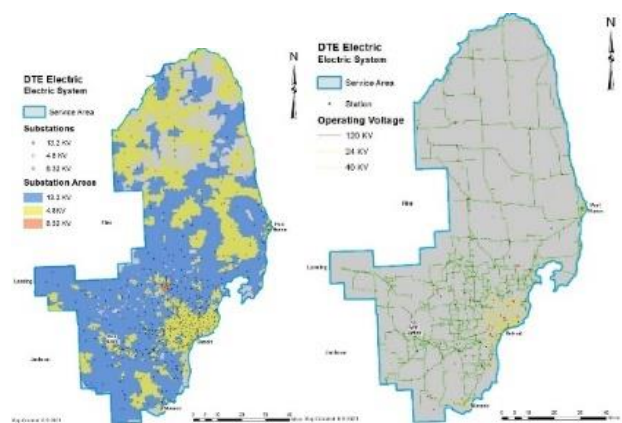


Exhibit A.2 Reliability Indices Definitions

Index	Full Name	Calculation
SAIFI	System Average Interruption Frequency Index	Total number of customer interruptions divided by the number of customers served
SAIDI	System Average Interruption Duration Index	Total minutes of interruption divided by the number of customers served
CAIDI	Customer Average Interruption Duration Index	Total minutes of interruption divided by the total number of customer interruptions

Exhibit A.3 Reliability Statistics - Excluding MEDs

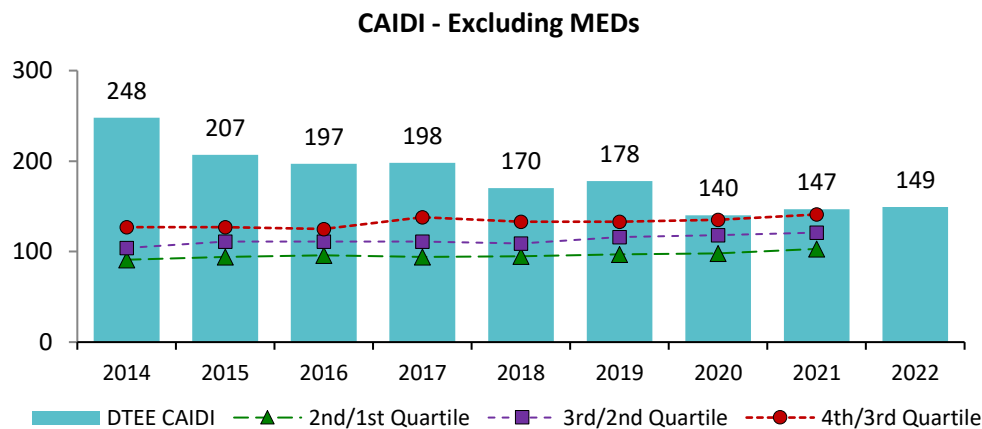
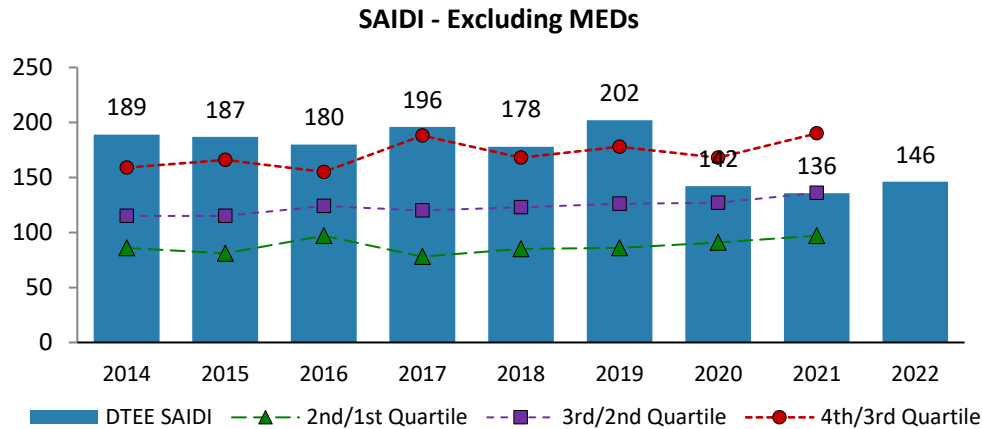
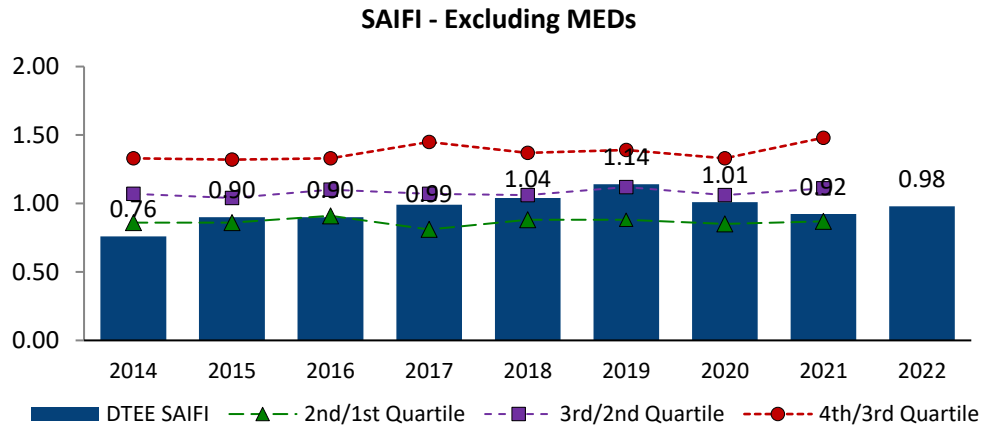


Exhibit A.4 Reliability Statistics - Catastrophic Storms (DTEE Definition)

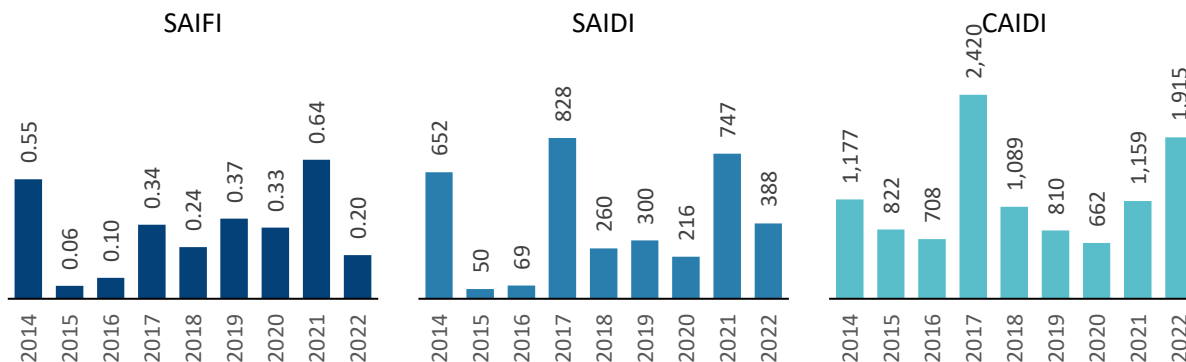


Exhibit A.5 Reliability Statistics – Non-catastrophic Storms (DTEE Definition)

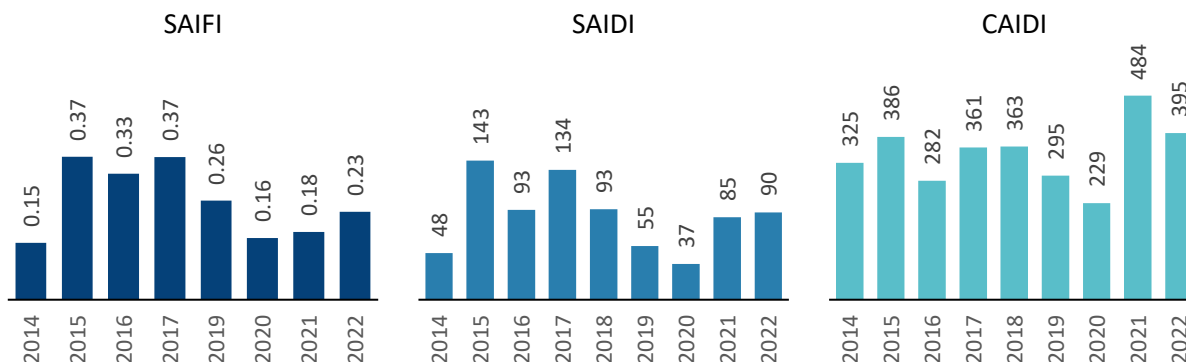


Exhibit A.6 Reliability Statistics - Excluding All Storms

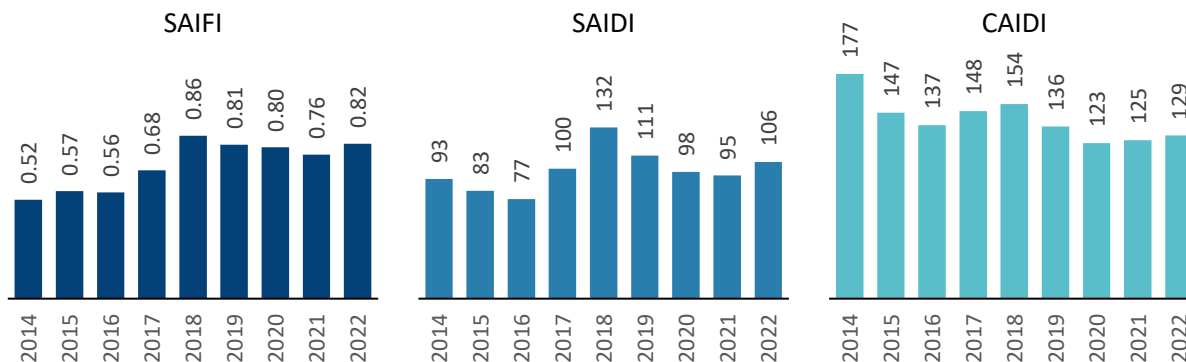
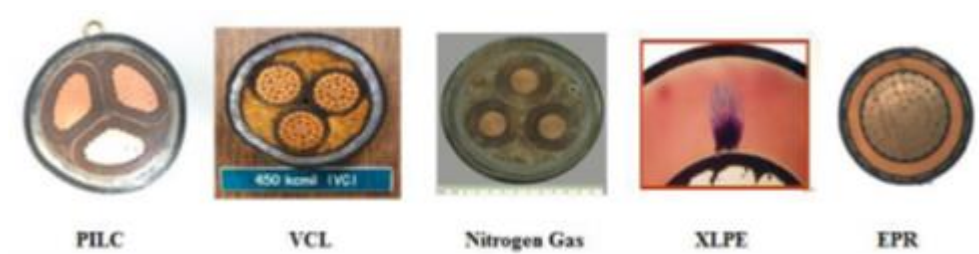


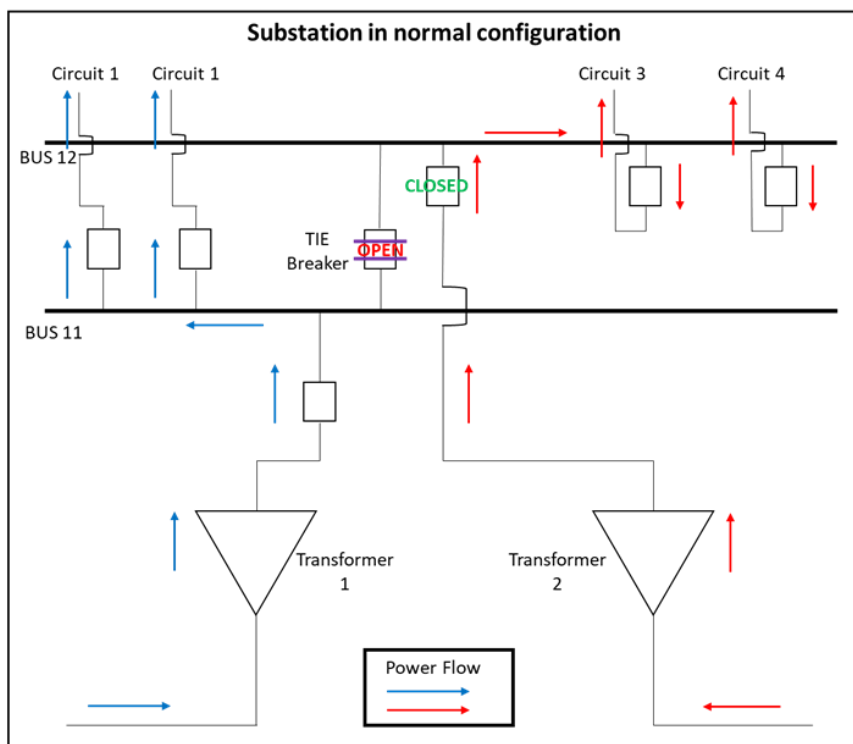
Exhibit A.7 Underground System Cable Types



Appendix B Infrastructure Redesign and Modernization

Appendix B.1 Distribution Load Relief Diagram and Tables

Exhibit B.1.1 Substation in Normal and Contingency States



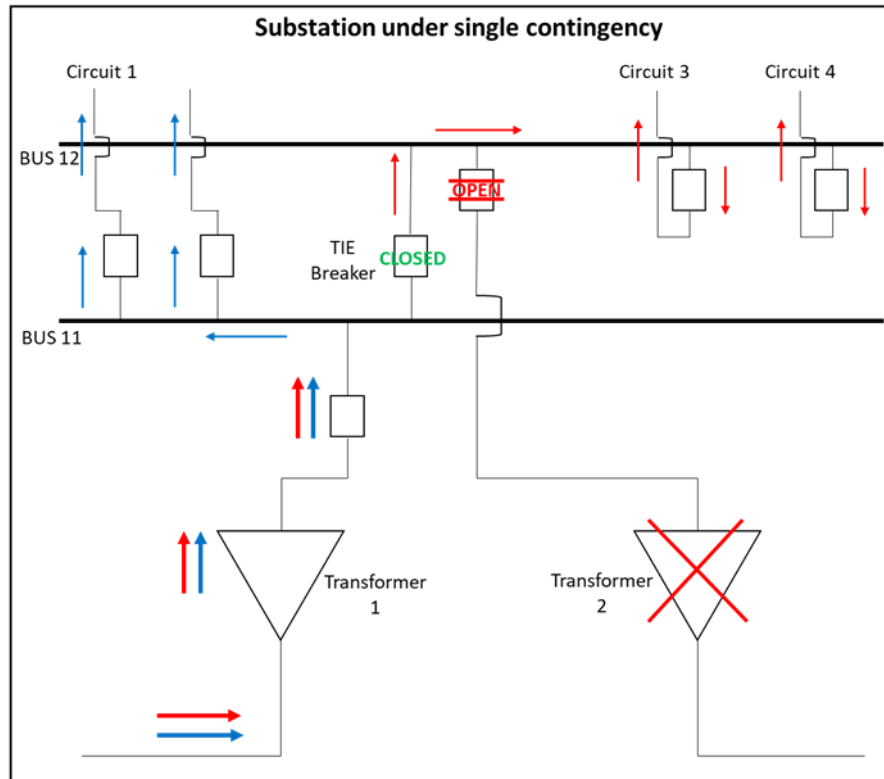


Exhibit B.1.2 Top 25 Highest Ranked Load Relief Substations – Project Summary

Index	Substation	Community	Project and Scope of Work
1	St. Antoine	Detroit	<u>CODI – Alfred Expansion</u> : Expand 13.2 kV Alfred substation
2	Alfred	Detroit	<u>CODI – Alfred Expansion</u> : Expand 13.2 kV Alfred substation
3	Garfield	Detroit	<u>CODI – Garfield Network Conversion</u> : - Rebuild 36 miles of network feeder cable - Replace or remove 78 netbank transformers - Convert 24 miles of overhead - Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation - Remove 4.8 kV and 24 kV cable and decommission Garfield substation
4	Cato (13.2)	Detroit	<u>CODI – Cato Substation Expansion</u> : Expand 13.2 kV Cato substation

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Index	Substation	Community	Project and Scope of Work
5	Temple	Detroit	<u>CODI – Midtown Expansion</u> : Expand 13.2 kV Midtown substation
6	Madison	Detroit	<u>CODI - Madison Conversion</u> : • Rebuild 31 miles of network feeder cable • Rebuild 30 miles of system cable • Replace or remove 92 netbank transformers • Convert three miles of overhead • Convert and consolidate the circuits to 13.2 kV fed by Temple substation • Decommission Madison substation
7	Jewell	Washington	<u>System Loading: Jewell</u> : • Build a new 13.2 kV substation • Build 6 miles of underground conduit and install 8 miles of underground cable • Establish 4 new distribution circuits to accommodate load transfers from Jewell circuits • Convert and transfer about 11 miles of overhead line from Washington and decommission Washington 4.8 kV substation
8	Walker	Detroit	<u>CODI – Islandview Substation and Walker Conversion</u> : • Construct new 13.2 kV Islandview substation • Convert 32 existing 4.8 kV circuits from Walker and Pulford • Decommission Walker substation • Decommission aging 24kV cables and infrastructure
9	Cody	South Lyon	<u>System Loading: Cody</u> : • Expand Cody substation • Establish 4 new circuits • Install 8 miles of underground conduit and 17 miles of underground cable • Reconnector 7.5 miles of overhead line
10	Hawthorne	Dearborn Heights	<u>4.8 kV Conversion: Hawthorne Relief and Circuit Conversion</u> :

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Index	Substation	Community	Project and Scope of Work
			- Extend overhead from Mallard distribution circuits and convert 4.8 kV areas out of Glendale and Hawthorne - Upgrade Biltmore 13.2 kV substation and establish 3 new distribution circuits - Replace switchgear at Villa substation - Expand Mallard substation and build two new general purpose substations to convert and remove load from Hawthorne, Glendale, Villa, and Daly substations
11	Cato (4.8)	Detroit	<u>CODI – Cato/Orchard Conversion</u> (Cato portion): - Rebuild 17 miles of system cable - Convert and consolidate the circuits to 13.2 kV fed by Temple substation - Decommission Cato 4.8 kV substation
12	Amsterdam	Detroit	<u>CODI – Amsterdam Conversion:</u> - Rebuild 12.3 miles of network feeder cable - Rebuild 50 miles of radial powerline system cable - Replace or remove 60 netbank transformers - Convert seven miles of overhead from 4.8kV to 13.2kV - Convert and consolidate the circuits to 13.2 kV fed by Stone Pool substation - Decommission Amsterdam substation
13	Daly	Dearborn Heights	Load relief will be provided by the 4.8 kV <u>Conversion: Hawthorne Relief and Circuit Conversion</u> project, see Index #10
14	Roseville	Roseville	<u>4.8 kV Barber Substation and Circuit Conversion:</u> - Build new 13.2 kV Barber substation - Convert 20 miles of 4.8kV to 13.2kV - Reconductor 3 miles of 3 phase 13.2kV - Install 1 mile of new 13.2kV conductor - Decommission Bunert substation
15	Howard	Detroit	<u>CODI – Howard Conversion:</u> - Rebuild 6 miles of network feeder cable - Rebuild 12 miles of system cable

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Index	Substation	Community	Project and Scope of Work
			- Replace or remove 89 netbank transformers - Convert three miles of overhead - Convert and consolidate the circuits to 13.2 kV fed by Corktown, St. Antoine, Cato, and Temple substations - Decommission Howard substation
16	Golf	Macomb	<u>System Loading: Kings Point</u> - Build new 13.2 kV Kings Point substation - Install 13 miles of system cable to establish the new 8 load carrying circuits and one throwover circuit - Reconductor 5 miles of overhead - Convert 3 miles - Install conduit and cable to establish 2 new circuits out of Golf substation
17	Cypress	Marysville	Load relief will be provided by completion of new industrial substation
18	Utica	Utica	Load relief will be provided by transfers between Utica circuits
19	Shaw	Imlay City	<u>System Loading: Brown City:</u> - Install new 13.2 kV substation at Bennett Station - Replace transformers at Marlette substation - Convert and transfer about 38.5 miles of Tacoma, Marlette, Brown City, and Shaw circuits to 13.2 kV - Decommission Brown City Substation
20	Slater	Brockway	<u>4.8 kV CC: Yale-Slater Decommissioning and Circuit Conversion:</u> - Build new 13.2 kV substation - Reconductor and convert 5.6 miles of single phase to three phase - Reconductor and Convert 25 miles of 4.8kV to 13.2kV

Index	Substation	Community	Project and Scope of Work
21	Wixom	Wixom	<u>System Loading: Wixom:</u> - Add a third transformer at Wixom substation - Replace existing switchgear with two 12-position switchgear - Build multiple miles of underground cable, conduit, and overhead lines)
22	Grayling	Shelby	Load relief will be provided by the construction of new Sigma substation as part of a new business and load growth projects
23	Boyne	Macomb	Load relief will be provided by the <u>System Loading: Kings Point</u> project, see Index #16
24	Snover	Snover	Load relief will be provided by a load transfer to an adjacent substation and circuit
25	Goodison	Oakland Twp	<u>System Loading: Goodison:</u> - Construct a new 13.2 kV substation - Establish two new distribution circuits to relieve load from Goodison - Install underground conduit and cable to connect to existing circuits - Reconductor 1.4 miles of overhead line and extend 2 miles of overhead

Exhibit B.1.3 Additional Load Relief Projects

Substation(s) / Location	Community	Project and Scope of Work
Berlin	Berlin Twp	<u>System Loading: Berlin:</u> Upgrade Berlin substation and split existing distribution circuit
Diamond	Dexter	<u>System Loading: Diamond:</u> Replace transformer #2 and upgrade substation equipment

Substation(s) / Location	Community	Project and Scope of Work
Disco	Sterling Heights	<u>System Loading: Disco:</u> Install 3 miles of underground cable and establish two new circuits out of Bronco substation to provide load relief to Disco substation and circuits
Globe	Vassar	<u>System Loading: Globe</u> Replace the existing transformer at Globe substation with a larger unit
Grenada	Ann Arbor	<u>System Loading: Grenada</u> • Build new 13.2 kV substation • Rebuild existing Grenada circuits and one circuit out of Wolverine substation • Convert and transfer load from adjacent Prospect substation and circuits
Lark/Spruce	Ann Arbor	<u>System Loading: Lark/Spruce</u> • Build new 13.2 kV substation • Split one Spruce circuit into two new Lark circuits • Reconductor almost 6 miles of overhead
Macomb	Clinton Twp	<u>System Loading: Macomb Substation</u> • Expand Macomb substation • Establish 4 new distribution circuits to relieve load from Macomb and adjacent substations and circuits
Malta	Sterling Heights	<u>System Loading: Malta Circuits</u> Establish three new distribution circuits at Malta to relieve load of existing circuits
Mayville	Mayville, Clifford	<u>System Loading: Mayville</u> • Build new pad-mounted 13.2 kV subtransmission distribution facility (STDF) • Convert and transfer load from Mayville and Clifford circuits
New Baltimore/Chesterfield	New Baltimore, Chesterfield	<u>System Loading: New Baltimore/Chesterfield</u> • Build a new 13.2 kV substation and upgrade New Baltimore substation

Substation(s) / Location	Community	Project and Scope of Work
		- Establish 5 new distribution circuits including 1.5 miles of underground cable installation and rebuilding 4 miles of overhead distribution - Rebuild 8 miles of overhead 40 kV line
Otsego/Capac	Imlay Twp	<u>System Loading: Otsego/Capac</u> - Build new 13.2 kV substation - Establish two new circuits to relieve 13 MVA of load from Otsego and Capac substations and circuits
Port Hope	Rubicon Twp	<u>System Loading: Port Hope</u> - Build new 13.2 kV subtransmission distribution facility (STDF) - Reconductor one mile of overhead - Transfer all Port Hope load to new STDF and decommission Port Hope
Port Sanilac	Port Sanilac	<u>System Loading: Port Sanilac</u> - Build new 13.2 kV substation - Convert and transfer load from Port Sanilac and Foster circuits - Decommission Port Sanilac substation
Richmond/Armada	Richmond, Armada	<u>System Loading: Richmond/Armada</u> - Upgrade Richmond substation - Transfer existing Richmond and Armada load - Decommission 4.8 kV sides of Richmond and Armada substations
Spokane/Seneca	Rochester Hills	<u>System Loading: Spokane/Seneca</u> Expand Spokane substation and establish 7 new distribution circuits to relieve Spokane and Seneca
Sterling	Sterling Heights	<u>System Loading: Sterling</u> Expand Sterling substation and establish three new distribution circuits
Tahoe	Novi	<u>System Loading: Tahoe:</u> Expand Tahoe substation and establish new distribution circuit

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Exhibit B.1.4 Projected Costs and Timeline for Load Relief Projects

Project	2024	2025	2026	2027	2028	2024-2028 Cost Estimate (\$ million)
System Loading: Jewell						\$23
System Loading: Cody						\$31
System Loading: Kings Point						\$29
System Loading: Brown City						\$17
System Loading: Wixom						\$29
System Loading: Goodison						\$18
System Loading: Berlin						\$5
System Loading: Diamond						\$4
System Loading: Disco						\$5
System Loading: Globe						\$3
System Loading: Grenada						\$39
System Loading: Lark/Spruce						\$13
System Loading: Macomb Substation						\$15
System Loading: Malta Circuits						\$1
System Loading: Mayville						\$15
System Loading: New Baltimore/Chesterfield						\$14
System Loading: Otsego/Capac						\$11
System Loading: Port Hope						\$3

Project	2024	2025	2026	2027	2028	2024-2028 Cost Estimate (\$ million)
System Loading: Port Sanilac						\$26
System Loading: Richmond/Armada						\$32
System Loading: Spokane/Seneca						\$31
System Loading: Sterling						\$11
System Loading: Tahoe						\$8

Appendix B.2 Subtransmission Tables

Exhibit B.2.1 Subtransmission Projects Summary

Project Name	Community	Scope
Subtransmission Redesign and Rebuild Projects		
Badax Transformer 102 Addition	Bad Axe	Expand Badax station by installing a new 40kV bus with additional positions and new transformer
Bernard	Wales Twp.	Install a capacitor at Bernard substation
Boyne	Macomb	- Expand Boyne station - Install 1.5 miles of new conduit and 40kV underground cable - Install 2.5 miles of new 40kV overhead lines - Reconductor overhead and underground on two trunk lines
Carpenter	Milan	Install a capacitor at Carpenter station

Project Name	Community	Scope
		- TIE 1568 – reconductor 6.1 miles of 40kV overhead and distribution underbuild - TIE 3705 – reconductor 6.5 miles of 40kV overhead and distribution underbuild
Custer Republic	Monroe	- Decommission transformer at Republic - Decommission and reconfigure trunk lines - Replace relay panels at Custer station
Derby	Vassar	Install two new transformers and associated equipment
Detroit Waste Water Maxwell Cable Replacement	Detroit	- Replace over 4,500 feet of underground cable - Replace over 4,500 feet of conduit
Hurst	Howell	Expand Hurst station
Imlay Rebuild	Imlay City	- Expand Otsego station - Decommission & remove 40kV busses and associated equipment at Imlay - Reconfigure tie lines by installing underground cable and overhead lines
Kennett	Pontiac	Complete decommission and equipment removal at Kennett substation
Mohican	Marysville	Complete decommission and equipment removal at Mohican substation
Oak Beach Capacitor	Port Austin	Install a capacitor at Oak Beach substation

Project Name	Community	Scope
		Install 40kV cap bank switcher with associated below grade and relaying equipment
Pigeon Area Improvement	Unionville, Sebawing, Kilmanagh, Pigeon, Bayport, Caseville, Kinde, Port Austin	- Expand Oliver station - Decommission 40kV equipment at Pigeon station - Extend conduit and cable on five tie lines - Extend 40kV overhead on four tie lines
Praxair	River Rouge	Upgrade equipment at Praxair substation to resolve operating concerns
Reverse Power Relay Scheme Program	Multiple	Upgrade relays, relay panels at various stations
Sandusky Station Rebuild	Sandusky	Expand and rebuild Sandusky station and substation
Sandusky Transformer 101 Breaker	Sandusky	Replace existing Transformer 101 secondary disconnect switch and associated equipment
Small Projects & Reserve	Various	Complete necessary work to address small overload issues
STPS6	Snover	Remove unused overhead subtransmission lines and associated equipment from former STPS6 site
Tempest Phase II	Pontiac	Rebuild Tempest substation to current standards
Thumb Electric Fault Isolation	Kinde, Watertown, Ubly, Owendale, Millington	Replace five 40kV pole top switches with new automatic pole top switches to support shutdowns and future maintenance

Project Name	Community	Scope
Tie 1423	Monroe	- Reconductor 17 miles of 40kV overhead lines and distribution underbuild and relocate out of deep right-of-way - Replace oil breakers at Rockwood and Custer stations
Tie 1473	Sumpter, Augusta, London, and Exeter Twps, Maybee, Raisinville	Reconductor 17 miles of 40kV overhead lines and distribution underbuild and relocate out of deep right-of-way
Tie 3205	Pigeon, Caseville, Oak Beach, Port Austin	- Install 28.8 miles of new 40kV overhead lines - Reconductor .7 miles of existing 40kV overhead lines - Decommission and remove 24.9 miles of existing overhead 40kV lines
Tie 3416	Bad Axe	- Replace transformers at Badax and Sullivan substations - Replace 1.6 miles of 40kV overhead lines and 1.6 miles of distribution underbuild
Tie 3705	Dundee	- Reconductor 1 mile of 40kV overhead lines - Upgrade relays at Carpenter station
Tie 4104 North	Sherman, Sand Beach	- Reconductor .02 miles of overhead 40kV lines and 16.4 miles of distribution underbuild - Reconductor 5.1 miles of distribution underbuild - Install 18.9 miles of new 40kV overhead lines and 2.8 miles of distribution underbuild

Project Name	Community	Scope
		- Decommission 17.3 miles of overhead 40kV lines - Upgrade Talbot station - Upgrade relaying and sectionalizing
Tie 4105	Lexington, Croswell, Port Sanilac, Applegate, Carsonville	Reconductor 36 miles of overhead 40kV lines and 19.2 miles of distribution underbuild and relocate out of deep right-of-way
Tie 5208	Milan, Belleville	- Remove 9.7 miles of overhead conductor - Install 14 miles of new 40kV overhead conductor - Replace oil breaker at Carpenter station
Tie 6147	Milford Charter Twp	Replace 5.7 miles of overhead 40kV lines
Tie 6602	Lima Twp	- Remove 3.75 miles of overhead 40kV lines - Install 3.95 miles of new overhead 40kV lines
Tie 6907	Rochester Hills	- Reconfigure Tie 6907 and Trunk 6941 - Install 1,700 feet of overhead conductor
Tie 7504	Novesta	- Reconductor 12.2 miles, install 4 miles, and remove 4 miles of overhead 40kV lines - Reconductor 2.7 miles of distribution underbuild - Install capacitor at Wilmot station and replace breakers and associated equipment
Tie 810 (Gramer)	Lenox	- Build new Gramer station - Reconfigure existing tie and trunk lines

Project Name	Community	Scope
		- Install 11 miles of 40kV overhead lines - Reconductor 16 miles of 40kV overhead lines - Decommission 5 miles of 40kV overhead lines
Trunk 0359	Detroit, Taylor	Replace 517 feet of 24kV underground cable and associated equipment
Trunk 1444	Monroe	Install capacitor at Trinity substation
Trunk 2308	Macomb	Rebuild 2.9 miles of overhead 40kV lines and distribution underbuild
Trunk 2419	Detroit	Replace .3 miles of underground cable
Trunk 2448	Detroit	Replace ~3 miles of underground cable
Trunk 2455	Detroit	- Install 1,000 feet of conduit with 4 new manholes - Install 2,000 feet of 40kV underground cable - Install 2,000 feet of 15kV underground cable - Remove 4.8 miles of underground cable
Trunk 328	Detroit	Replace 3.4 miles of underground cable
Trunk 3508	Troy	Replace 2.8 miles of underground cable
Trunk 3509	Troy	Install new position at Troy station to create new trunk line to relieve Trunk 3509
Trunk 3546	Troy, Birmingham, Royal Oak	- Install .9 miles of conduit - Replace 2.9 miles of underground cable

Project Name	Community	Scope
Trunk 362	Detroit	Replace 3.3 miles of underground cable
Trunk 4217	Grosse Pointe, Harper Woods, Detroit	- Replace 2.1 miles of underground cable and associated station work - Install new 40kV breaker and associated equipment at Erin station - Replace Vernier substation transformer 3 secondary breaker and cable terminations
Trunk 4245	Eastpointe	- Install 3,000 feet of new conduit - Install 17,500 feet of new underground cable - Remove 17,500 feet of existing underground cable
Trunk 4266	Eastpointe	- Replace 2.5 miles of underground cable - Replace oil breakers at Erin and Savoy stations
Trunk 4601	Burlington, Burnside, Marlette	- Expand Bennett station by installing a new bus and associated equipment - Install 11.1 miles of new 40kV overhead lines
Trunk 4911	Lenox	- Trunk 4911 – reconductor 12.4 miles of 40kV overhead lines and move to road right-of-way - Expand Victor station and install cable and conduit and 3.6 miles of 40kV overhead to establish new Trunk 4950 - Trunk 4962 – relocate 1 mile of 40kV overhead lines
Trunk 7105	Southfield	Expand Southfield station by installing a new position with associated equipment

Project Name	Community	Scope
		Install 1.53 miles of new cable for new trunk line
Trunk 7150	Southfield	Replace 21,775 feet of underground 40kV cable
Trunk 7386	Madison Heights, Warren	- Upgrade ~5,500 feet of underground cable - Install ~2,611 feet of new conduit
Waterman	Detroit	Consolidate at decommission breaker positions at Waterman station
Other Subtransmission Investment Projects		
Ann Arbor system Improvements	Ann Arbor	- Construct 2 new substations and 5 miles of 120kV lines - Reconfigure subtransmission tie lines and trunk lines
Station Upgrade: Cortland Station Expansion	Highland Park	Purchase property adjacent to Cortland station and expand the station
Subtransmission Breaker Short Circuit Violations	Multiple	Install reactors or replace breakers at multiple stations
Transformer High Side Protection Program	Various	- Install high side switching devices on 19 subtransmission and distribution transformers located at 15 different stations - Eight of these transformers will also require relocation and/or replacement due to space constraints at their current sites
TCHPP (Trenton Channel Power Plant) Switchyard Upgrades	Trenton	Upgrade Trenton Channel switchyard to current standards

Exhibit B.2.2 Projected Investment and Timeline for Subtransmission Projects

Project	\$ Millions					
	2024	2025	2026	2027	2028	Total Investment 2024-2028
Badax Transformer 102 Addition						\$9
Bernard						\$1
Boyne						\$0
Carpenter						\$8
Custer Republic						\$2
Derby						\$9
Detroit Waste Water Maxwell Cable Replacement						\$2
Hurst						\$4
Imlay Rebuild						\$2
Kennett						\$1
Mohican						\$1
Oak Beach Capacitor						\$1
Pigeon Area Improvement						\$47
Praxair						\$3
Reverse Power Relay Scheme Program						\$4
Sandusky Station Rebuild						\$1
Sandusky Transformer 101 Breaker						\$4

Small Projects & Reserve						\$3
STPS6						\$0
Tempest Phase II						\$8
Thumb Electric Fault Isolation						\$1
Tie 1423						\$3
Tie 1473						\$2
Tie 3205						\$54
Tie 3416						\$5
Tie 3705						\$9
Tie 4104 North						\$37
Tie 4105						\$30
Tie 5208						\$5
Tie 6147						\$0
Tie 6602						\$5
Tie 6907						\$2
Tie 7504						\$32
Tie 810 (Gramer)						\$49
Trunk 0359						\$0
Trunk 1444						\$1
Trunk 2308						\$6

Trunk 2419						\$1
Trunk 2448						\$3
Trunk 2455						\$4
Trunk 328						\$4
Trunk 3508						\$4
Trunk 3509						\$2
Trunk 3546						\$7
Trunk 362						\$4
Trunk 4217						\$7
Trunk 4245						\$16
Trunk 4266						\$9
Trunk 4601						\$33
Trunk 4911						\$23
Trunk 7105						\$2
Trunk 7150						\$2
Trunk 7386						\$5
Waterman						\$3
Ann Arbor system Improvements						\$14
Station Upgrade: Cortland Station Expansion						\$7
Subtransmission Breaker Short Circuit Violations						\$1

Transformer High Side Protection Program						\$22
TCHPP (Trenton Channel Power Plant) Switchyard Upgrades						\$2

Appendix B.3 Conversion Tables

Exhibit B.3.1 4.8 kV Conversion Projects

Project	Community	Drivers	Scope of Work
Almont Relief and Circuit Conversion	Almont Twp	- Provide load relief at Almont substation - Replace aging infrastructure - Increase jumpering capability	- Build a new 13.2kV substation - Transfer Almont load to new substation, converting to 13.2kV - Reconductor 15-16 miles of overhead backbone - Establish new jumpering points - Decommission Almont substation
Ann Arbor AC Network Conversion	Ann Arbor	- Address aging infrastructure - Provide capacity for new growth	- Install new underground conduit and cable including secondary cable - Replace existing netbank transformers with dual voltage netbank transformers
Barber Substation and Circuit Conversion	Roseville, Warren, Eastpointe	- Provide load relief - Provide capacity for new load growth - Address aging infrastructure - Increase jumpering capability	- Install a new 13.2kV substation - Convert and transfer load to new substation - Decommission Bunert substation

Belleville Substation	Belleville	• Address aging infrastructure • Provide jumpering capability • Provide capacity for new load growth	• Install a new 13.2kV transformer and replace Transformer 3 with a new 13.2kV transformer • Rebuild and convert over 10 miles of overhead to 13.2kV • Create new jumpering points with adjacent substations
Birmingham Decommissioning and Circuit Conversion	Birmingham, Bloomfield Hills	• Substation outage risk for Birmingham substation • Provide capacity for new load growth • Address aging infrastructure	• Transfer Birmingham load to adjacent substation • Rebuild Birmingham substation to new 13.2kV substation • Convert and transfer load from Birmingham and Quarton Road substations to new substation • Decommission Quarton Road substation
Buckler Circuit Conversion	Ann Arbor	• Provide load relief and capacity needs for downtown Ann Arbor • Increase jumpering capability	• Transfer remaining circuits from Argo to Buckler substation, converting them to 13.2kV
Calla Circuit Conversion Phase 2	Dexter	• Provide load relief to Diamond substation and capacity needs for Dexter • Increase jumpering capability	• Rebuild 4.8kV Diamond circuits to 13.2kV and transfer to Calla substation
Cortland / Oakman / Linwood Consolidation	Detroit	• Reduce trouble events and O&M expenses by decommissioning two aging, underutilized 4.8kV substations	• Consolidate 4.8kV Oakman and Linwood into 4.8kV Cortland substation to decommission aging substation equipment and system cable

Griffin and Williamston 4.8kV ISO Conversions	Webberville, Williamston	Address aging overhead infrastructure	Convert 13.6 miles of overhead from 4.8kV to 13.2kV and remove three ISO down transformers
Grosse Pointe Substation and Circuit Conversion	Grosse Pointe, Eastpointe, Detroit	- Provide capacity for new load growth - Address aging infrastructure	- Install a new 13.2kV substation - Convert and transfer load from Vernier, Wayburn, Grosse Pointe and Denver substations - Decommission Wayburn, Grosse Pointe and Denver substations
Hawthorne Relief and Circuit Conversion	Dearborn Heights	- Provide load relief - Address aging infrastructure - Provide capacity for new growth	- Extend overhead from Mallard distribution circuits and convert 4.8 kV areas out of Glendale and Hawthorne - Upgrade Biltmore 13.2 kV substation and establish 3 new distribution circuits - Replace switchgear at Villa substation - Expand Mallard substation and build two new substations to convert and remove load from Hawthorne, Glendale, Villa, and Daly substations
Hemlock Decommissioning and Circuit Conversion	Ann Arbor	- Provide capacity for new load growth - Address aging infrastructure - Provide load relief	- Install STDF (Subtransmission Distribution Facility) and transfer load from Hemlock substation. - Rebuild Hemlock as a new 13.2kV substation - Install new 13.2kV substation - Convert and transfer load to new substation

			•
Hilton Circuit Conversion Phase 2	Ferndale, Oak Park	• Provide capacity for new load growth • Address aging infrastructure	• Expand Hlton Road substation • Convert and transfer load from Ferndale, Hazel Park and Woodside substations to expanded Hilton Road substation • Decommission Hazel Park, Ferndale and Woodside substations and 24kV trunk lines out of Lincoln station
I-94 Substation and Circuit Conversion (Promenade)	Detroit	• Replace aging infrastructure • Reduce trouble events and O&M expenses • Provide capacity to emerging businesses such as I-94 industrial park	• Construct a new 13.2kV substation • Convert existing 4.8kV circuits from Lynch, Lambert and Pulford • Decommission Lynch, Lambert and Pulford substations • Decommission trunk lines
Lapeer-Elba Expansion and Circuit Conversion (Apollo)	Lapeer, Elba Twp	• Provide load relief • Replace aging infrastructure • Increase jumpering capability	• Build a new 13.2kV Apollo substation • Convert and consolidate 4.8kV circuits from Elba and Lapeer substations to 13.2kV • Decommission the 4.8kV portion of Lapeer substation • Decommission Elba and 40kV tap to substation • Transfer a portion of Hunter's Creek to new substation to improve reliability
McKinstry Substation Decommission	Detroit	• Decommission substation as all load has been transferred to	• McKinstry substation will be decommissioned and all equipment removed.

		Zenon or West End substations due to the Gordie Howe International Bridge project	
Monroe Substation and Circuit Conversion	Monroe	- Address aging infrastructure - Provide load relief - Provide capacity for new growth	- Construct a new 13.2kV substation - Convert and transfer load from Front and Roosevelt substations to the new 13.2kV substation - Decommission Front and Roosevelt substations
Pine Grove Substation Relocation and Conversion	Port Huron	Substation needs to be relocated due to bridge plaza expansion	- Construct a new 13.2kV substation - Re-route subtransmission lines to feed new substation - Convert and transfer all load from Pine Grove substation - Decommission Pine Grove substation
Pittsfield Substation and Circuit Conversion	Ann Arbor, Ypsilanti	- Provide capacity for new load growth - Address aging infrastructure - Provide load relief	- Install a new 13.2kV substation - Convert and transfer load from Pittsfield to new substation - Decommission Pittsfield substation
Quincy Conversion	Yale	Aging wood foundation supporting transformer at Quincy substation	- Construct new pad-mount substation - Convert 3 miles of overhead and install ISO-down transformers - Transfer load from Quincy to new pad-mount - Decommission Quincy substation
Rochester Decommissioning	Rochester Hills	Address aging infrastructure	Construct a new 13.2kV substation

and Tienken Relief		• Provide load relief • Provide jumpering capability • Provide capacity for new load growth	• Convert and transfer load from Rochester and Tienken substations to the new 13.2kV substation • Decommission Rochester substation
Royal Oak Substation and Circuit Conversion	Royal Oak	• Reduce customer interruptions with increased protection • Provide capacity for new load growth	• Construct a new 13.2kV substation • Convert existing 4.8kV circuits from Whittier and Webster substations to new substation • Convert and transfer 4.8kV Lincoln load to 13.2kV side of Whittier substation • Decommission 4.8kV Whittier, Webster and Lincoln substations
Scotten Circuit Consolidation	Detroit	• Increase jumpering capability	• Decommission and consolidate three circuits at Scotten substation
Unionville DC 301 B1 Conversion – resolve voltage problems	Unionville	• Increase motor start capabilities in the area that will reduce flicker	• Convert a portion of the circuit to 13.2kV, relocate regulators and capacitors on the circuit
Unionville Decommissioning and Circuit Conversion	Unionville	• Provide load relief • Provide capacity for new load growth • Address aging infrastructure • Provide jumpering capability	• Install a new 13.2kV substation at existing Randolph Station • Reconductor 16 miles of overhead line • Convert and transfer load from Unionville and Fairgrove to the new 13.2kV substation • Decommission Unionville substation
White Lake Decommission and Circuit Conversion	White Lake	• Provide load relief • Replace aging infrastructure	• Build a new 13.2kV substation with four load carrying circuits

		- Allows for jumpering (existing 4.8kV is islanded – surrounded by 13.2kV) - Provide capacity for new load growth	- Convert and transfer load from White Lake substation and a portion of Clyde substation - Establish new jumpering points - Decommission White Lake substation
Yale-Slater Decommissioning and Circuit Conversion	Yale	- Address aging infrastructure - Provide capacity for new load growth - Increase jumpering capability	- Construct new 13.2kV substation - Reconductor, convert and transfer load from Slater and Yale substations to new 13.2kV substation - Decommission Slater and Yale substations
Zenon Circuit Conversion Phase 2	Detroit	- Addresses aging infrastructure - Provide jumpering capability - Provide capacity for new growth	- Expand Zenon Substation - Convert and transfer load from Scotten and Westend substations - Decommission Scotten and Westend substations

Exhibit B.3.2 Projected Costs and Timeline for 4.8 kV Conversion Projects

Project	\$ Millions					
	2024	2025	2026	2027	2028	Cumulative 2024-2028 Investment
Almont Relief and Circuit Conversion						\$1
Ann Arbor AC Network Conversion						\$34
Barber Substation and Circuit Conversion						\$17
Belleville Substation						\$11
Birmingham Decommissioning and Circuit Conversion						\$27
Buckler Circuit Conversion						\$4
Calla Circuit Conversion Phase 2						\$9
Cortland / Oakman / Linwood Consolidation						\$1
Griffin and Williamston 4.8kV ISO Conversions						\$13
Grosse Pointe Substation and Circuit Conversion						\$52
Hawthorne Relief and Circuit Conversion						\$62
Hemlock Decommissioning and Circuit Conversion						\$58
Hilton Circuit Conversion Phase 2						\$82
I-94 Substation and Circuit Conversion (Promenade)						\$140
Lapeer-Elba Expansion and Circuit Conversion (Apollo)						\$27
McKinstry Substation Decommission						\$2
Monroe Substation and Circuit Conversion						\$2
Pine Grove Substation Relocation and Conversion						\$24
Pittsfield Substation and Circuit Conversion						\$60
Quincy Conversion						\$0

Rochester Decommissioning and Tienken Relief						\$20
Royal Oak Substation and Circuit Conversion						\$34
Scotten Circuit Consolidation						\$2
Unionville DC 301 B1 Conversion – resolve voltage problems						\$1
Unionville Decommissioning and Circuit Conversion						\$13
White Lake Decommission and Circuit Conversion						\$40
Yale-Slater Decommissioning and Circuit Conversion						\$47
Zenon Circuit Conversion Phase 2						\$85

Appendix C Technology and Automation

Appendix C.1 Grid Automation Investments

Technical Training Center DER lab

The Technical Training Center (TTC) DER lab is DTEE's location to test and validate technology and processes before deployment to the system and validate NWA controls and approaches. The TTC DER lab co-locates the training center of excellence to allow for field and engineering input on new technology with infrastructure to test interactions of technology and compatibility of operating practices. Hardware in the loop simulation of controls and grid models coupled with real time networking and cyber security testing allows complex control schemes to be tested thoroughly before deployment on a specific project using the actual control hardware.

The testbed also allows testing and training of DER systems available to customers to determine how control modes function, interactions between devices and test cyber security and integration. Further, the DER Lab allows the development of inspection and commissioning procedures and safety training, pilot documentation for installation of initial units in the grid and working with

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DTE Electric Company

2023 Distribution Grid Plan U-20147

manufacturers on issues that are found in testing to reduce issues that DTEE must resolve. In a recent case, the DER Lab staff found an issue in the wiring of a popular inverter and worked with the manufacturer to change the installation manual and provide instructions to Michigan solar installers. This specific inverter has been mis-connected by developers in more than 50 installations in DTEE's grid since its introduction in early 2023 and these installations had to be corrected to avoid improper operation and safety issues for DTEE personnel and the customers.

Gateways & Grid edge services

As DER sites become more capable, the functions the devices can perform are moving from passive to active management. Most existing inverters have initial settings applied at installation with no intent to change them dynamically, advanced inverters can be actively controlled in real time and have their settings updated to adapt to changes to the grid configuration. The mechanism to provide this real time change management and coordination can be done through a grid edge gateway device that is installed alongside the DER.

While simple DER may be able to operate independently, when multiple DER need to coordinate, they may not all be able to communicate the same protocol or have the same capabilities. and A gateway can provide this point of coordination. This is especially useful in distribution microgrids where multiple devices may need to coordinate to reconfigure the microgrid state or boundaries and may not be all owned by the same party or be at the same location.

Grid edge gateways are needed at the interface point between customer resources and utility resources to act as a security and control coordination point. Grid edge gateways communicate with both the customer DER(s) and the utility SCADA/DERMS systems and provide a cyber security firewall and intrusion detection capability to allow necessary communications to flow between the utility and the DER.

Gateways provide many functions including cyber security, centralized management, anomaly detection, coordination of resources, protocol conversion, deconfliction of control commands, sitewide optimizations, and alarming and event logging. Gateways initially are being deployed as part of real time SCADA controls for large DER such as solar and wind parks but will become increasingly necessary to coordinate distribution microgrids and Non-Wire alternatives.

Michigan Public Service Commission

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2023 Distribution Grid Plan U-20147

Currently gateways are collections of off the shelf hardware that are packaged into control cabinets, longer-term dedicated gateway devices that perform the communications, cyber security, control and optimization functions. The gateways being utilized implement Open FMB (Open Field Message Bus) as a standardized and interoperable data exchange framework and an application suite called Open DSO which has been demonstrated by several utilities to be able to provide DER and microgrid coordination and has the ability to have modular optimization and protocol adapters using cyber security best practices. Gateways are becoming standardized through IEEE1547.10 which defines the behavior and function of gateways. Eventually certified third party gateways may be available that allow for utility applications to be securely loaded onto them.

Load and Electric Vehicle managed charging

Transportation electrification will be highly dependent on the ability to manage vehicle charging loads, anticipate peak demands, and implement programs to incentivize off peak usage. While programs and incentives are developing, this program is focused on technical integrations to the Company's control systems to ensure cyber security and reliable integration of electrified transportation.

This program also includes fast charger modeling and assessments that plan for the impact of high-powered chargers and characterization of dense electrified transportation loads including power quality metering and analysis at several sites in the service territory. These investments support multiple demonstration implementations including electrification of public transportation and fleets and DTEE's truck stop of the future project in Redford that is a partnership with Daimler Trucks.

Managed charging technology and communications standardization and integration are specific focuses of the program. This includes the DOE supported EVs-at-RISC technology demonstration program to create a reference architecture and implementation for cyber secure managed charging using interoperable protocols. This project is in partnership with Idaho National Labs (INL), Oakridge National Laboratory (ORNL) and other partners and demonstrates utilizing advanced security approaches such as zero trust and advanced firewalls to provide a reference framework for distribution scale charge management. The project will be demonstrating capabilities in the Corktown area through 2025. This program also includes demonstrations of

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2023 Distribution Grid Plan U-20147

digital, policy-based program management that implement digital contracts to the DER. Longer term, several projects with secondary use and repackaging of transportation storage for grid reuse will be undertaken as batteries become available. Vehicle to Grid (V2G) and vehicle to load integrations to the interconnection process including communications integration to allow management are being investigated and demonstrated.

New Technology evaluation

As new automation and grid hardware is brought online, use of a rigorous and standardized process for evaluation, testing, and documenting the technology implementation is employed. This project includes field demonstrations and training center implementation of technology before it is made broadly available into standard designs and use.

CVR/VVO

The initial CVR/VVO program pilot was completed in 2022 and the program was paused for 2023. The program achieved the expected results, but it was identified that the method implemented resulted in an unsatisfactory number of Load Tap Changer (LTC) operations and a more optimized method such as the ADMS VVC capability needed to be used instead. In late 2023, an RFP will be conducted for measurement and verification, reporting, and consulting that will be an ongoing aspect of the program until these functions can be fully automated in house. In 2024, the CVR/VVO program will be restarted, the initial work will be to complete field construction of jobs that were planned in 2022 but put on hold. The remaining budget will be used to replace a substantial number of capacitor controls on circuits ahead of substation work. These capacitor controls will reduce operation of the LTC by substituting operation of the capacitor bank for fine voltage adjustment and transient voltage issues. The ADMS VVC module will be enabled to control all suitably configured capacitor and voltage regulation devices on the system and CVR will be enabled where all work on a substation bus is completed. The approach allows the ADMS CVR module to optimize the system voltage continuously in any location where voltage control devices are located. The CVR module will be enabled where substation LTC control and field installation of capacitors has been completed.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

From 2025 onward the program will focus on replacement of 100% of all poletop capacitor and regulator controllers with SCADA enabled controls, analyzing all circuits for appropriate capacitor and regulator placement, moving and supplementing capacitor placement where needed. The capacitor control replacement will have an added value of providing sensing capability at each location which will be used by the ADMS. This will be done while maintaining a low, but sustainable schedule of substation LTC upgrades each year that allows for appropriate coordination and shutdowns. Substation LTC control upgrades to support CVR/VVO functionality will be built into design standards and replacements. This will result in a wider deployment of smaller initial benefits because most circuits will be optimized with the pole top devices alone, but this will allow for increased visibility into the system response to VVO through the ADMS and get critical data back to planning tools to verify CVR opportunities. This work will be coordinated with 4.8KV conversion and replacement and the circuit automation programs to ensure that device is placed where needed. The program will also investigate the use of circuit capacitors as part of the optimization and alternatives to large station capacitors. Pole top regulator SCADA controls and smart inverter controls will also be added to the program over the next 5 years. Additional work in the program will include development of sufficient tracking algorithms, analysis and reporting to measure benefits vs expected results and improvements to internal planning tools to allow CVR/VVO to continue to be operated as circuits change due to load changes, circuit reconfiguration and DER installations.

Appendix C.2 Grid Management Investments

DERMS & FERC2222

The Distributed Energy Resource Management System (DERMs) is composed of five major functions which will be implanted as part of this investment:

- Program assignment with end point Registration/deregistration
- Interfaces between the ADMS and aggregator/end point systems/APIs
- Dispatch optimization
- Program compliance
- Short term DER forecasting for load and supply

The initial deployment of DERMs will be to integrate all Company owned DER that is not connected through SCADA as well as all existing DR programs and systems such as Interruptible

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2023 Distribution Grid Plan U-20147

air conditioning and heating to the ADMS. Once these integrations are done, major third-party integrations will be prioritized depending on the implementation of market aggregators, FERC2222, or tariff programs.

The company will begin by selecting a DERMS vendor with deployment of an initial DERMS system. This initial system will be sized to cover expected DERMS needs for the next five years which is anticipated to control active DER endpoints along with a substantial amount of the customer base in DR end points. Afterwards, or as needed, reevaluation of the market space will be made to determine if the system will continue to be expanded or if substantial improvements in the industry have been made in DERMS capabilities. Adjustments to this plan will be made as needed to comply with State and Federal requirements and programs.

Distribution System Operator Support tools (DSO) include dynamic analysis, optimization analysis of DER, portfolio optimization, management of customer DER programs, short term forecasting, Locational Value Analysis, and linkages to the Generation Management System (GMS) for market functions such as oversight, will be evaluated. These functions will be served by a combination of DERMS, enhancements to Power runner, and tools yet to be identified as the maturity of commercially available toolsets improves.

FERC841/2222 Coordination

While compliance for MISO requirements and process is several years out, some of the foundational investments in this space have long implementation times and require augmenting and reworking many existing processes. Investments in preparing for implementation have already started in cases where there is a high degree of certainty that the functionality is needed. Tools will be needed to support the control room in identifying constraints that are created by market participating entities on distribution circuits and aggregations and the associated communications needed with all of the affected entities.

Tools will also be needed to inform the system supervisor of the impact of operating decisions in constraining market participants and aggregations and of the constraints that aggregations that are responding to market actions. These tools will need to evaluate short term planning horizons of a few minutes to a few weeks to allow for appropriate notifications and constraint identification.

Process changes will be required to support the coordination and notification processes. Control process and signals will be developed to inform participants and aggregators of system constraints, shutdowns, and maintenance. Short term forecasting and prediction tools will need to be integrated into the process to anticipate possible power flow changes from market and aggregator operations.

Enhancements to the interconnection process will be made to allow for compliance to the program registration and validation requirements that are required by MISO. Enhancements in planning processes and tools will be made to perform the appropriate studies and scenarios that will be created by more load and generation volatility.

Cyber security and SCADA tool server

This program establishes work practices, substation hardware specifications, and back-end software to implement cyber security policies in an auditable and efficient manner, utilizing Subnet solutions on the SCADA tool servers to provide cyber security interface for patching, firmware updates, password updates and security auditing. This program also establishes standards for new networked substations and includes cyber security consulting and best practices benchmarking as well as security testing.

Prior years of project implemented SCADA tool servers in both the Downtown and Ann Arbor data centers. Ongoing work includes (1) implementation of interfaces to SCADA tools including power quality metering tools such as Honeywell Connexo and Schneider PME to the PI historian, (2) interfaces between cybersecurity and vendor specific asset management tools for field devices that are part of the cyber security and settings management programs.

Automation Configuration and Testing database

This project replaces in-house developed software with a vendor-supported and industry standard system to provide a single source of protection and automation settings data, as well and a consistent interface for automation device change management, auditing, and lookup of settings. Automated interface with test equipment to facilitate test data collection and record keeping, as well as interfaces to asset management and network management data will allow SCADA, ADMS, and planning tools to have the most up-to-date data. This project also enables the use of

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DTE Electric Company

2023 Distribution Grid Plan U-20147

advanced automated test sets for technicians to streamline testing. Remote access through SCADA tool servers to validate settings will also be enabled.

Appendix C.3 Distribution Planning Investments

Load Allocation Analytics Program

Power Runner is a software tool designed to incorporate AMI, SCADA, and forecast data into one data set of historical and future hourly intervals to serve the requirements of the planning tools for load allocation and data for analysis.

Power Runner requires interfaces to many data systems including the data lake, NMS, SCADA (DOPI), AMI (AMIPI), and Power Quality Metering (Schneider PME and Honeywell Connexo). Power runner will be used to improve data quality by identifying gaps in meter and SCADA data and inconsistencies that can then be fed back to the NMS for correction. Power Runner will be integrated with the ADMS 'as switched model' to provide an accurate historical record of the state of the system down to the customer meter level and validate automation performance. Power Runner will provide short term forecast information and incorporate long term forecast data and scenarios from corporate load forecasting for use in planning simulations. Power Runner will be used to update and automate the ALA and TLA processes and assess system losses, DR and DER program compliance, and validate forecast data. Enhancements to DOPI and AMIPI systems to support Power Runner automation and performance will be included. Data analysis tools from SEEQ to do time series data science analysis and scripted automation of historical trend analysis are also planned to be interfaced to Power Runner.

CYME enhancements Program, Advanced Project Manager and Dynamic Data pull and reporting

The CYME planning tool will be enhanced by acquiring new modules and working with the vendor on the product roadmap that is shared by other utilities to support evolving needs in grid planning. The CYME system will be upgraded on a regular schedule to incorporate new vendor functionality as it becomes available.

The CYME dynamic data pull module will be implemented to collect information from Power Runner. This will allow studies to select specific time periods for analysis or do an 8760 analysis of an entire year. CYME server will be implemented to offload studies that will run for a long time

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

to a central server that can implement GPU and machine learning optimizations and reduce the time to run studies and scenarios. CYME Advanced Project Manager will be implemented and integrated with Maximo to allow each workorder to be linked to the electrical system model changes and the start and end date of the work to be simulated allowing a comprehensive schedule of system upgrades, load additions, and interconnections to be studied across multiple years and alert the engineer if a schedule change will adversely impact the reliability or loading of a circuit. The CYME gateway will be enhanced to pick up additional data from the Asset and GIS systems and further automate the network model validation processes including incorporating the sub transmission and substation models and AC network and the linkage to PSSE models.

CYME will be integrated with the interconnections processing tool PowerClerk to improve screening and study, and automate common validations and checks such as system fault current, voltage min and max, short circuit current, phase imbalance, jumpering, and loop scheme validation. Integration of CYME with Maximo CUs will allow for more accurate engineering estimates and updates. Integration of LIDAR data into CYME reliability analysis will refine SAIFI, SAIDI, CAIDI improvement analysis for project changes. Interfaces from CYME to PSSE will be developed to meet MOD-32 modeling requirements and to coordinate model updates between the distribution and sub transmission and transmission. Automations will be developed to streamline and automate modeling and scenario setup.

A single system to track future customer load additions and changes, interconnections, and their configurations will be created to feed the ADPS and allow for scenario analysis. A single system to track customer program participation, tariff and market participation will be developed to allow the planning tools to update scenario assumptions on DER utilization, DR responses and validate requirements for programs and FERC 2222. Enhanced reporting for the engineering teams will be provided to consolidate the very large amounts of data produced by the new planning tools and scenario analysis to identify limits, constraints, and areas for more focused study.

Forecasting and propensity analysis Program

Use case specific forecasting and propensity tools will be evaluated and it is likely that a combination of the IFS forecasting scenarios and specific technology propensity tools will be integrated to develop the specific scenarios that the ADPS will use. These tools need to not only inform the potential adoption scenarios of various technologies in both time and location, but also

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2023 Distribution Grid Plan U-20147

be able to provide the base parameters to allow the power flow simulations to incorporate the specifics of each technology and control methods.

The propensity and forecasting solution will need to create useful and practical scenarios and bounds for the ADPS tool to process. Anticipated models that are needed will include, but are not limited to, weather models, home and commercial energy usage models, HVAC electrification, EV charging adoption, managed charging models, solar adoption, energy storage mode analysis, vehicle to grid and industrial, and fleet electrification models. Energy storage specifically needs specialized analysis because of the need to charge and discharge the storage without violating constraints and the limited duration of energy storage requires a time series analysis across many different usage cycles.

Advanced machine learning will be needed to identify scenarios that represent the right boundaries to study in order to reduce the computational needs as well as the amount of analysis that is needed to validate and review the scenarios.

Power Runner will be integrated with the Itron Metrix forecast outputs created by the load forecasting team. This will provide consistency for the feeder level forecasting that will be used for scenario analysis in ADPS/CYME. Power Runner will also supply the cleansed SCADA data from PI to the Itron Metrix forecasting solution and provide reporting on the deltas between SCADA, AMI and forecasting for further data analysis. Power runner will be enhanced to provide short range forecasting (<1 month) that can be used for study of switching and planning coordination of shutdowns.

In the next 5 years the combination of ADPS and Power Runner will be used to bring Integrated resource planning and distribution planning closer with the longer-term goal of reaching a suite of tools that allows for Integrated Distribution Modelling (IDM).

Interconnections Process Enablement Program

The MPSC released final interconnection rules under U-20890 and is has open proceedings on U—21117 interconnection rules and procedures. There are several short- and longer-term investments to meet compliance with these orders and to improve efficiencies of the new interconnection processes. Compliance with new interconnection rules, automating to improve efficiency, and processing time are major portions of the Operational Technology investment in

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

this program; the program also includes engineering consulting and benchmarking support through EPRI and other vendors on industry best practices, customer facing design and interconnection study process enhancements and tools updates.

The updates to the interconnection rules drive investments in two key exiting tools for interconnection processing, PowerClerk and its integration into SAP commerce cloud. PowerClerk is an online application system for interconnection used by the Company and many other utilities to support interconnection applications and tracking and processing, including digital signatures of documents. At the end of 2022 the Company completed the integration between PowerClerk and Commerce cloud. This integration provided several benefits to customers and to the efficiency of the interconnection process: first, the integration allowed for single sign on so that Power Clerk applicants, both customers and contractors, are able to use a DTEE login, and second, it enabled electronic payment of interconnection fees and automatic creation of internal orders to post the payment against. This greatly reduced the number of physical checks the company received for interconnections and for those applications paid for electronically, eliminated a significant amount of time waiting for mail delivery and check processing. The new rules implement several changes that require upgrades to this system. Fees and fee calculations have changed, new interconnection statuses have been added that require tracking, and several new sub processes were added, such as pre application, that require new software development and testing to meet the requirements. Further enhancements are also planned to incorporate changes to data and model collection during the application and study process to implement updates to MISO Affected System Study process (AFS), and to capture appropriate data to aggregate into yearly planning models at MISO.

Initial Investments will be made in PowerClerk to adopt the new processes, filters and process steps including timelines and reporting requirements to support fast track, non-export and study tracks, and the new pre-application process. In commerce cloud, interfaces to adopt the new payment structures and process steps will be created. PowerClerk enhancements will be made to support updated reporting and timeline tracking requirements from the new rules as well as enhancements to the DTE website interconnection pages to provide required information, documentation, and procedures. Improvements will be made to the registration system to allow for self-registration of installers, and Business-to-Business customers. Payment will be expanded to cover the new pre-application process as well as study fees. Additional integrations will be

added between PowerClerk and the GIS system to allow for completed projects to be automatically added to the mapping system, replacing a manual process today and to support reporting and modeling on pending applications. Additional work will be done in SAP to facilitate adding appropriate transaction codes for different program and meter configurations.

Additional investments will be made to facilitate the screening of interconnections and the study of interconnections. Some of the core system modelling investments are covered in the prior section, but specific integration will be made with the planning tools and PowerClerk to implement automation of the interconnection screens where possible as the screening process in many cases requires a fault or power flow study to get the correct location specific data. The automation will be designed to capture the information from the application and application, insert the interconnection into a temporary study of the current and known future changes to the configuration of the system and then apply the appropriate automated calculation and then return the results to PowerClerk reporting for inclusion into the interconnection technical review package. For studies, a significant amount of time is needed to prepare the study data package and investments into automating the generation of the study and study scenarios from the applicant's data will be made to streamline processing timelines and effort. As other aspects of the ADPS platform are completed, this study automation can be further expanded to run common models and incorporate future grid changes and forecast scenarios into the model runs automatically. Longer term automation of study result interpretation and study reports will be targeted to further streamline the process. Initial investments may include decision support for the interconnection engineer on screening and study results to recommend if additional study is needed or if the results are sufficient to move the project forward.

Another area of investment will be in processes and tools to validate program and tariff compliance for DER. This will not only function as a mechanism to validate customer compliance to specific program and tariff requirements but also provide a continuous program auditing capability to detect gaps in the process before they have any impacts to customers. Some of these compliance functions will be implemented in Power Runner enhancements. Future enhancements may include machine learning algorithms, the use of other supplementary data sets and advanced pattern analysis, especially where storage or other power control systems are used, and meter data alone may be insufficient to determine the driving factors behind the behavior of the DER.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Enhancements will be needed to support FERC2222 implementation. Investments will be made in the application intake process which will be implemented into Powerclerk as a separate program that will provide a linkage between the market participation request and the interconnection while allowing each to proceed according to their appropriate compliance processes. There will also be required validation studies as part of the process that will be automated where possible to maintain the ability to meet timelines. Additionally, investment will be made in integration of load modifying and demand response resources into the modeling process and interconnection process which will impact studies, hosting capacity and scenario planning during peak and light loading conditions. Finally, necessary reporting and coordination functions will be integrated as identified when MISO releases their procedural requirements over the next few years.

One potential area of increased efficiency in the interconnection process is to utilize machine learning algorithms to evaluate interconnection requests. A large amount of the time spent analyzing the request is comparing the application information to the supporting information such as the one line and site plan. While final review by an interconnection engineer is likely in the case of complex systems, validation and consistency checking of more straightforward systems may be able to benefit from machine learning analysis to identify inconsistencies or missing elements. The identification process will be integrated into the PowerClerk application process right after application submission to identify issues as soon as possible in the process so that feedback can be provided to applicants.

Another area of planned investment is in web portals and website enhancements that provide customers additional information and data access on DER integration specific to their location and use case to provide decision support. These tools will be coordinated with other customer decision support analytics for rates and programs to help guide customers to energy efficient solutions and bill savings. These investments are still being investigated.

In the next few years, as Interconnections become more common, work will be undertaken to merge the new service, method of service, and interconnection process into a single workflow. This transition will occur over several years in multiple steps and all of the investments for this transition have not been completely quantified, however, it is likely that much of the work done on interconnection processing will be used to enhance new service processing. As an example, given the rapid pace of vehicle to grid (V2G) development for electric vehicles, PowerClerk will be used

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2023 Distribution Grid Plan U-20147

to capture applications for bi-directional capable chargers, and to facilitate support of future bi-directional charging in the ADMS, DERMS, and in the circuit analysis.

Hosting capacity Program

In the Commission's June 30th, 2023, Grid Integration Study Report, recommendations were made regarding hosting capacity. These recommendations will benefit directly from investments in the Advanced Distribution Planning System, which are foundational data sources for improved hosting capacity calculations and visualizations.

The initial scope includes improving data availability and map capabilities to provide greater accessibility and interactivity while maintaining security of critical infrastructure and customer information. This work also includes implementing capacity map visualizations and vocabulary to provide consistency of communication about hosting capacity data. Other areas of investment in this program are automating hosting capacity through use of toolkits to improve the frequency of hosting capacity updates and hosting capacity tools for load and distributed generation to allow for visualization of the grid's ability to incorporate additional load and generation.

The commission requested enhancements to hosting capacity for DER as well the creation of a loading capacity map during workshops in 2022, and in the MIPower grid report. Specific requirements may come out of future working groups. An initial loading capacity map is being developed with a public release planned for late 2023. The loading capacity map will be updated once a year based on the annual planning cycle. Internal enhancements to streamline the update process and incorporate specific study data will be ongoing. Enhancements to the hosting capacity and loading capacity maps to increase frequency of updates and increase detail of data will be directly dependent on completion of the ADPS scope. There is currently no specific timeline for public facing enhancements. With integration of CYME and EPRI drive, more granular hosting capacity data can be generated in both high penetration areas, and those that have undergone detailed study. Research in Hosting capacity methods is ongoing, especially in how to integrate storage, power controls, and bi-directional EV charging and this will drive future investment in this area.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Hosting capacity investments are composed mostly of the visualization and presentation of the data that will be derived from the other investments in Advanced Distribution Planning System study tools.

Sub transmission modelling Program

Modeling the interface between the distribution and transmission systems is a critical aspect of operational and reliability planning. This analysis uses different tools than the distribution circuits primarily due to requirements in modeling the bidirectional power flow on the sub transmission tie line system and incorporating DTEE assets into the transmission model maintained by MISO for reliability studies and interconnection process compliance. Several investments in enhancements in this area are required to maintain compliance and to facilitate system planning and investment.

TSAT is required to validate customer defined models and verify modelling and study information for transmission affected systems. TSAT is a tool new to DTEE and many of the vendors that do MISO modelling but is required to generate models for MISO planning scenarios and to incorporate specific customer DER models. PSSE enhancements following requirements from MISO and MOD-32 to produce new model scenarios and synchronize study information with ADMS and CYME will also be part of this program. Scripting will be created to initially allow CYME to roll up distribution connected DER and properly reference between the models to meet the requirements of affected system studies and yearly model updates.

Longer-term there will be a need to merge the distribution models and transmission models to be able to execute more complex multi scenario analysis and wide area optimization. The full scope of these integrations is still being evaluated, but likely will include integrations between IRP planning tools, transmission modeling tools, and distribution modelling tools to create an Integrated Distribution Modeling system.

Power Quality analysis Program

This project includes the identification and purchase of a power quality tool that can collect power quality information from the SCADA tool servers, line sensors, and other meters and correlate events based on time and system impact. Analysis of voltage swells, sags, harmonics, flicker, and waveform events with predictive analytics to identify event precursors and forensic analysis

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

tools to apply sequence of events and precise time stamp synchronization for failure analysis are all functionalities that will be considered when selecting the toolset. Visualization tools to map events and trends over time and on a spatial and schematic view of the system and to generate heat maps to identify patterns and related events. The initial scope is to utilize Schneider PME as the storage and visualization tool for users and then later to integrate machine learning to analyze waveforms against known failure modes and event patterns and identify incipient faults or failures and help troubleshoot outage and power quality events. PSCAD is a detailed power modeling tool that allows for study of harmonic interactions, dynamic response, high frequency transients, and detailed analysis of abnormal power quality events. Additional licenses will be required as more DER require modelling and have interactions with grid equipment that will need to be assessed for upgrades.

Substation and structural Design tools Program

The MicroStation CAD tools will be enhanced with the integration of MicroStation design libraries with Maximo Compatible Units and Bill of material generation to reduce manual work and validate accurate material orders. Additional features include (1) 3D CAD design that allows for automatic evaluation of clearances and conflicts and rapid generation of different cross sections, plans, and views; (2) automatic wire routing and schematic validation; (3) comprehensive document and version management system for design revisions and print creation; and 4) incorporation of metadata into design library to allow for analysis of material requirements.

PLSCAD is used for individual engineered poles and overhead structures where additional structural calculations are needed where structural design requires detailed mechanical analysis such as in critical crossings or constrained spaces where guy wires cannot be used and is an advanced CAD tool to do specific modelling on engineered poles and specific structure designs.

Spidacalc is used for all pole designs to ensure that the poles are meeting design standards for Grade B construction. Enhancements to the Spidacalc tool are used by planners to calculate the appropriate design for poles. Licensing for structural design tools like RISA3D is also anticipated. RISA3D is an advanced mechanical and civil design tool to validate structure loading for substations and below grade structures. Bluebeam is another tool that will need investment as it provides print mark up, collaboration and red lining, at a significant savings in engineering and field labor time, freeing those resources to take on the backlog of other work.

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

One area of new investment will be in LIDAR and spatial assessment tools which includes evaluating and selecting a tool set that allows for incorporation of LIDAR data into planning tools and assessing clearances to vegetation, ROW/easement, truck accessibility, Line sag, risk of vegetation impact to lines and structures, identification of joint use changes, and pole loading changes from design, identifying equipment configuration and pole top arrangement, equipment identification, and contributing to asset health assessments. Additionally, the ability to incorporate photographic and event information into the geospatial toolset to provide a single location for viewing spatially located images and data will be investigated.

Appendix D Stakeholder Engagement

Exhibit D.1 Key Themes from Customer Feedback (February 2023 Ice Storm)

Key Themes from Customer Feedback regarding February 2023 Ice Storms	DTEE's Plan to Address Customer Feedback
Frustration over frequency and duration of outages	DTEE plans to invest \$9 billion in grid improvements over the next five years by focusing on the four key areas the Company knows make a significant difference in reliability – tree trimming, infrastructure resilience and hardening, infrastructure modernization, and technology and automation. Each of these investment programs is detailed in this plan.
Dissatisfaction with electric rate increases	Upgrading the grid to a 21 st century standard requires the investments outlined in this plan. Specifically, Section 6 contains information on the benefits that can be expected from the proposed level of investment. The Company intends to remain transparent in how those investments are made, which is executed through the rate case process in coordination with the MPSC and participating stakeholders.
Desire for clean energy resources, including rooftop solar	DTEE's proposed investments to upgrade the grid will support additional capacity for clean energy resources, like electric vehicles, rooftop solar and other distributed energy resources. In addition, Section 3 contains a distributed generation/distributed storage growth scenario. ⁶⁶
Challenges reaching energy provider via phone and imprecise communications	DTEE's customers deserve as clear and as accurate of communications as possible and they deserve to be able to

⁶⁶ Separate from the DGP, DTEE's approved Integrated Resource Plan settlement agreement (U-21193) includes an increase in the DG cap from 1% to 6%.

<https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000008puPjAAI>

regarding outages/restoration efforts	contact the Company easily. Reference new Section 15.5 on outage/restoration estimates.
Discontent with outage credit compensation	Michigan's Service Quality and Reliability Standards for Electric Distribution System rules establish a bill credit for customers. Michigan is one of a select few states in the country with these customer credits. Due to the widespread impact of the February ice storm, DTEE voluntarily applied an outage credit for qualifying customers. In March 2023, the MPSC made this credit automatic for qualifying customers. ⁶⁷

Appendix E Detroit Targeted Study

On September 18, 2022 the MSPC requested a case study of the impacts of socioeconomic data analysis and comprehensive analysis of alternatives for the 4.8kV system within the geographic area of Detroit bounded by DTEE's fiber loop. Expectations of the study included generating insights on how to best support service reliability for customers within the boundary, as well as to inform DTEE's broader efforts to increase reliability for customers within its surrounding vulnerable communities. DTEE completed the study and shared results with stakeholders at the August 2023 Technical Conference.

Appendix E.1 Area of Analysis

The geographic area examined in the study was the city of Detroit territory bounded by the DTEE telecommunications fiber loop. The scope of the analysis was the 4.8KV system within this boundary, consisting of forty-five 4.8KV substations and eight 13.2kV substations. The map in Exhibit E.1.1 illustrates the study area and identifies the forty-five 4.8KV and eight 13.2KV substations. The study area only included substations that were strictly contained within the study territory. The study encompassed 2,107 miles of overhead circuits and equipment, 622 miles of underground circuits and equipment, and 267,366 customers.

Substations outside of the city limits were excluded even if they were in the fiber loop. However, all circuits that originate from the substations within the study area were included even if they extended beyond the city of Detroit boundary. This is because the 4.8KV system was assessed

⁶⁷ See MPSC final order in Case U-20629.

<https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000007IzfgAAC>

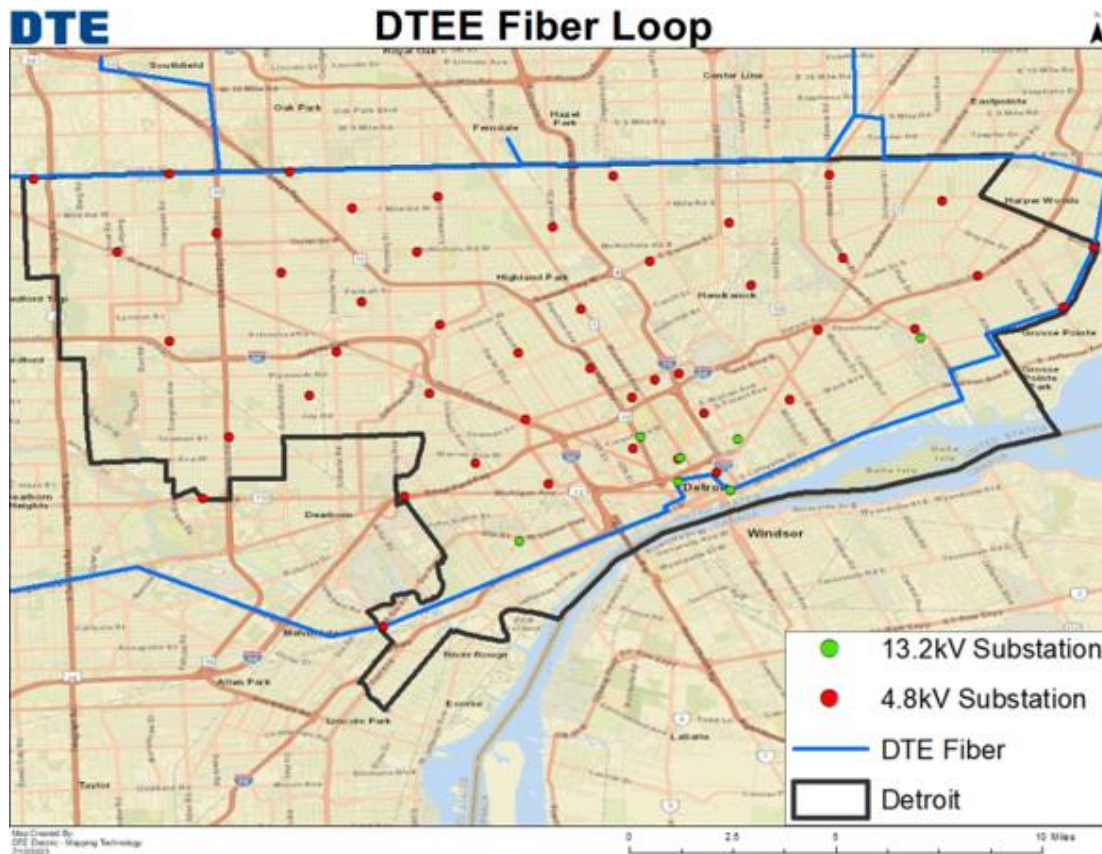
Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

at the substation level, and it is necessary to include all the circuits originating from a substation to determine the condition of the substation.

Exhibit E.1.1 DTEE Fiber Loop (Detroit)



Appendix E.2 Methodology for Evaluating Substations

To measure substation performance, metrics were identified for evaluating each of the 4.8KV substations in the study. Then, a score for each metric was used to indicate the performance of a single substation relative to all other substations in DTEE's electric grid. The following four metrics were utilized to provide a directional picture of the overall condition of each of the substations in the study; the metrics selected for the study are consistent with how DTEE measures the performance of its overall system.

- **The substation MiEJScreen tool score:** The substation's Environmental Justice Score calculation leveraged the state of Michigan MiEJScreen score assigned to each census tract. All customers in a single tract were assigned the same EJ score. The circuit EJ score

was first determined using a weighted average as a calculation of the individual scores of customers on that circuit. Then the Substation EJ score was determined using a weighted average calculation of individual scores of circuits that roll up to each substation. A high EJ score indicates that customers served by that substation experience a higher pollution burden and vulnerability when compared to those served by substations with a lower score. Each substation with an EJ score of 80% or greater was defined as a vulnerable community substation.

- **Wire Down Exposure (Safety)** - The Substation Wire Down Exposure (Safety) metric evaluates the safety risk associated with each station. The metric is calculated by dividing the total number of wire downs over a 5-year period by the number of overhead miles and then multiplying by the total number of customers served. Substations with only underground circuits were omitted from this calculation. A substation with a low customer count has a lower safety risk than another substation with a similar wire down density, but a higher customer count. Substations with a Wire Down Exposure in the fourth quartile, relative to all DTEE substations, were considered for a safety mitigation solution.
- **Reliability**- The Substation Reliability metric is measured using a 5-year average of System Average Interruption Duration Index (SAIDI). Substations with a Reliability in the 4th quartile, relative to all DTEE substations, were considered for a reliability mitigation solution.
- **Capacity**- The Substation Capacity metric is a measure of the electrical demand that a substation can accommodate. This was calculated by dividing the substation 2022 Peak MVA by the substation firm rating, or the maximum amount of electricity that a substation can supply under a single contingency without damage to the equipment. Substations with a capacity over 100% were considered for a capacity mitigation solution in this study.

Collection and assessment of these metrics provided a comprehensive framework for measuring the physical and socioeconomical conditions of customers within the fiber loop territory as well as the means to evaluate them against other substations in the DTEE service territories.

Appendix E.3 Findings

The above analysis identifies points where the metrics indicate that a mitigation solution is needed for each of the 4.8KV substations in the study. DTEE leverages a range of solutions to address

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

Wire Down Exposure, Reliability, and Capacity concerns. Exhibit E.3.1 summarizes the various solutions that can be implemented along with their relevant use case, cost, and complexity.

Exhibit E.3.1 Solution Options

	Improved Safety/ Wire downs	Improved Reliability	Increased Capacity	Use case	Cost Level	Execution Complexity
Tree Trimming				Improve reliability/safety if area is off-cycle	Low	Low
4.8kV Hardening				Improve reliability and safety, remove arc wire	Medium	Low
Conversion				Relieve capacity constraint and provide significant safety/reliability improvements	High	High
Microgrids + Pre-conversion				Potential to provide highest reliability and resiliency	Very High	Very High
DERs & Storage				Small/moderate load relief	Medium	Medium
Energy Efficiency				Small load relief	Low	Medium

Hardening, Conversion, or Microgrids + Pre-conversion are the best safety mitigation solutions. Tree Trimming of off-cycle circuits, Hardening, Conversion, and Microgrids + Pre-conversion will yield the most effective results for improving reliability. DERs & Storage and Energy Efficiency are most effective for addressing capacity challenges. The biggest challenges for the 4.8 KV substations in the study area are safety and reliability. The Tree Trimming program has a goal to reach a 5-year cycle by 2025, after which Tree Trimming of these circuits will be critical for maintaining the benefits incurred, but it will not yield additional reliability or safety benefit for on-cycle circuits. Therefore, the best solutions to implement to yield additional reliability and safety benefits are Hardening, conversion, or Microgrids +Pre-conversion. Of the substations evaluated by the study, only one (DENVR) was over capacity, but DERs & Storage was not a viable solution in this case as the capacity needed is greater than 3 MVA.

Appendix E.3.1 Completed and Planned Work

DTEE has actively worked in the Detroit Targeted study area over the past several years under its capital investment programs. the Company will continue to address the needs within the study territory through its strategy for future investment. Subsequently, twenty-nine of the forty-five 4.8KV substations in the study area have capital work that is either already completed or is in

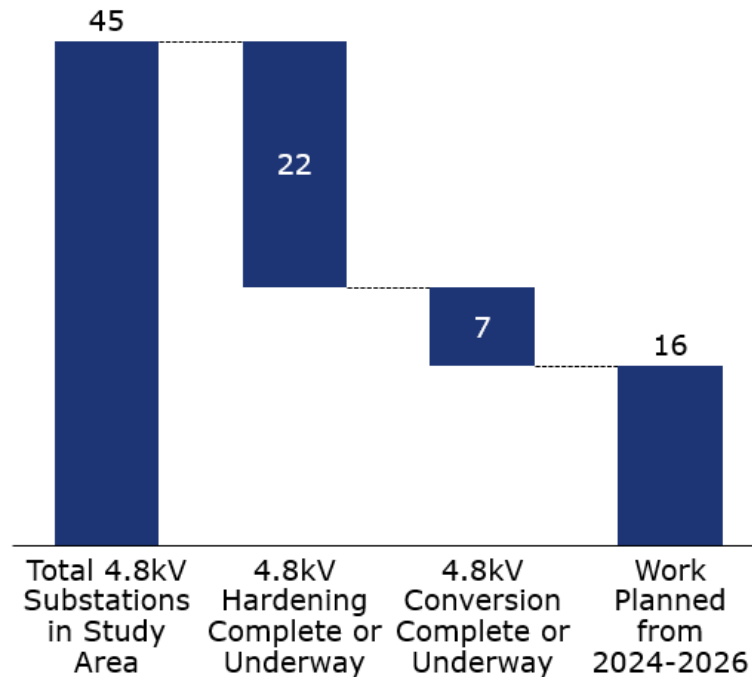
Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

progress. An additional sixteen have capital work that is planned from 2024 to 2026. Exhibit E.3.1.1 summarizes the status of capital work for 4.8KV substations in the fiber loop.

Exhibit E.3.1.1 Capital Work Plan 16.5.2 Targeted Study Findings



Conclusion

DTEE is actively investing to enable a reliable and resilient grid for the vulnerable communities in its service territory. Investigation of the 4.8kV system in the Detroit Targeted Study provided key insights on challenges the grid faces when servicing customers within the study area. DTEE's past and future planned capital investment, along with the proposed solutions set for each substation, address the needs of the 4.8KV system in the Detroit Targeted Study territory. The Company will proactively monitor the progress of the ongoing and planned work in the study area for reliability improvements and continue collaborating with stakeholders to identify potential opportunities on how to best support the customers in this area.

Appendix F Top 50 Strategic Capital Programs and Projects Based on GPM

Rank	Capital Program/Project
1	Pole and Pole Top Hardware (PTMM)
2	4.8 kV Circuit Automation
3	Automation: 13.2kV Circuit Distribution
4	CODI: Charlotte Network Upgrade
5	4.8 kV CC: ISO Conversion Program
6	Substation Risk: Apache
7	4.8 kV Hardening
8	4.8 kV CC: Buckler Circuit Conversion
9	4.8kV CC: Barber Substation and Circuit Conversion
10	CODI: Garfield Network Upgrade
11	Subtransmission Redesign & Rebuild: Bernard
12	Subtransmission Redesign & Rebuild: Trunk 4217
13	Subtransmission Redesign & Rebuild: Tie 6907
14	Subtransmission Redesign & Rebuild: TIE6147
15	Subtransmission Redesign & Rebuild: Boyne
16	Substation Risk: Chestnut
17	4.8 kV CC: Hawthorne Relief and Circuit Conversion

18	Frequent Outage Program (CEMI)
19	4.8 kV CC: Zenon Circuit Conversion Phase 2
20	CODI: Howard Conversion
21	Subtransmission Redesign & Rebuild: Trunk 3509
22	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion
23	URD Replacement Program
24	Cable Replacement Program
25	4.8 kV CC: Belleville Substation and Circuit Conversion
26	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker
27	8.3 kV CC: Pontiac Overhead Conversion
28	Subtransmission Redesign & Rebuild: Trunk 3508
29	Breaker Replacement Program
30	System Loading: Otsego/Capac/Shaw
31	4.8 kV CC: Monroe Substation and Circuit Conversion
32	System Loading: Brown City
33	Subtransmission Redesign & Rebuild: Trunk 2419
34	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
35	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
36	Subtransmission Redesign & Rebuild - Carpenter
37	System Loading: Macomb/Golf

38	4.8kV CC: Hemlock Decommissioning and Circuit Conversion
39	System Loading: Richmond/Armada
40	System Loading: Jewell
41	Substation Risk: Savage
42	Subtransmission Redesign & Rebuild: Tie 6602
43	Subtransmission Redesign & Rebuild: Tie 4105
44	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)
45	Subtransmission Redesign & Rebuild: Trunk 362
46	CODI: Amsterdam Upgrade
47	Subtransmission Redesign & Rebuild: Thumb Electric Fault Isolation
48	Subtransmission Redesign & Rebuild: Trunk 328
49	Subtransmission Redesign & Rebuild: Derby
50	System Loading: Globe

Appendix G Distribution Plan Requirements

Category	Distribution Plan Requirement (MPSC Order text)	Order /Date Page	Incorporation into the DGP
Reliability Metrics	The Commission is seeking future distribution plans to include: Expected measurable improvements resulting from the proposed distribution investments Benchmark reliability performance measures, such as SAIDI, SAIFI, CAIDI and CEMI against peer companies in the industry and identify areas of improvement	U-20147 2022-09-08 (p69)	Section 4 State of the Grid – charts show historic and forecasted improvements. Additional information is included in Appendix A
	The Commission adopts the recommendation by AEE/EIBC for the utilities to “construct SAIDI, SAIFI, and CAIDI statistics with and without major events instead of using the MED construct	U-20147 2022-09-08 (p70)	Appendix A.3 shows reliability metric charts excluding MED
	The Commission has requested information about how and, by how much, the Company’s hardening and tree trimming work is expected to improve reliability	U-20147 2022-09-08 (p69)	Tree Trim, Hardening, Reliability model sections (6) - point to the charts & tables in these sections
Energy and Environmental Justice	The Commission acknowledges the company’s commitment to develop a comprehensive environmental justice plan for its distribution system considering the reliability of service in communities identified by the MiEJScreen tool, and continued efforts to work with the Staff to provide data at a more granular level. Therefore, in future rate cases and distribution plans, DTE Electric shall “include future analyses, like overlay maps, charts, graphs, and other displays, that provide a visual or data informed understanding C19of more holistic impacts of electric infrastructure investments on customer communities.”	U-20836 2022-11-18 (p463)	EJ plan, analysis, and charts are included in Section 12

Investment Prioritization and Pilot Requirement	In either future rate case or next distribution plan, submit targeted strategic undergrounding pilot proposals using the objective criteria for pilots set forth in Case No. U-20645	U-20147 2022-09-08 (p73-74)	Undergrounding approach, pilots, and projects are discussed in Section 9.4
	The Commission is seeking more information on the distribution system conversion plans (i.e., more information on upgrades, ranking, where to start, undergrounding plans already in process, etc.)	U-20147 2022-09-08 (p73-74)	Section 9.3 discusses the Company's plans for conversion in detail
	The Commission is seeking a comparison of tradeoffs between grid hardening, undergrounding, and upgrading/converting, using appropriate BCA tests to determine the most reasonable and prudent path forward for various circumstances	U-20147 2022-09-08 (p72-73)	Current cost benefit approach discussion included in Section 12.1. The grid hardening discussion included in Section 8.2
	The Commission is adopting the Staff's recommendations in the May 27, 2022, comments on guidance for future plans. The Commission is requesting the following: -Problem description, goals, and possible solutions determined through community and third-party engagement, -Summarize full set of alternatives analyzed before determining the selected solution, Desired utility learnings or system outcomes, -Identification of investment locations overlayed with socioeconomic context, such as the MIEJScreen information, and electric distribution system information (4.8kV, 13.2kV, substation type and density, etc.).	U-20147 2022-09-08 (p74-75)	The information requested here could be found in: - Project summaries (rate case) - Stakeholder Engagement Section 17 - EJ Section 12.2
Performance Based Regulation	The Commission highlighted that utilities provided insufficient information to address the issue of financial incentives and penalties. In this regard, a MI Power Grid	U-20147 2022-09-08 (p71)	The Company's activity in this area is discussed in Section 12.3.1

	order is expected to be issued at the end of this year and additional guidance will be provided		
	The Commission cannot stress enough its expectation that DTE Electric will invest the amounts approved for strategic capital improvements and not shift them to other categories such as emergent replacement and other reactive spending. As such, the Commission may be willing to consider a long-term investment recovery mechanism (similar to the IRM for the gas Main Renewal Program first approved in the April 16, 2013 order in Case No. U-16999) to ensure that the spending included in rates for strategic capital improvements—including the ultimate conversion of DTE Electric’s distribution grid—is spent for these purposes, and to provide greater long-term certainty on recovery of reasonable and prudent costs related to these strategic distribution grid investments. The Commission expects that DTE Electric will include in any such proposal a full description of costs and benefits, as well as associated timelines.	U-20836 2022-11-18 (p76 - 77)	IRM Section (12.3.2)
Benefit Cost Analysis	The Commission is seeking information on the utilities’ investment programs, including benefit costs analyses (BCAs) in order to gauge the most reasonable and prudent paths for improving reliability	U-20147 2022-09-08 (p73-74)	Section 12.1 discusses the current cost benefit approach (GPM)
4.8kV Studies and Investments	The Commission also finds the Staff’s request for DTE Electric to work with the Staff and interested stakeholders to develop “a case study on the impact of socioeconomic data analysis and more comprehensive analysis of alternatives for the 4.8 kV system within the Company’s metro Detroit fiber loop” to be reasonable. The Commission directs DTE Electric to file this study in a future rate case or distribution plan, informed by stakeholder input and reflecting the learnings derived from the technical conference(s) detailed above	U-20836 2022-11-18 (p463 & 92 - 93)	Appendix E include the Company’s Detroit Targeted Study in detail

	Include in next DGP a detailed description of plans regarding grid hardening and conversion including timelines and technical conference learnings	U-20836 2022-11-18	Detail plans for Hardening and Conversion are discussed in detail in Section 8.2 and 9.3 respectively

Table of Exhibits

EXHIBIT 1.2.1 DTEE SUBSTATIONS BY TYPE AND VOLTAGE	8
EXHIBIT 1.2.2 DTEE SUBTRANSMISSION CIRCUITS BY VOLTAGE	9
EXHIBIT 1.2.3 DTEE TRANSFORMERS BY VOLTAGE LEVEL	9
EXHIBIT 1.2.4 DTEE DISTRIBUTION CIRCUITS BY VOLTAGE	9
EXHIBIT 1.3.1 2021 DGP PLAN KEY INVESTMENT PROGRESS	11
EXHIBIT 2.0.1 DTEE ORGANIZATIONAL PLANNING OBJECTIVES	17
EXHIBIT 3.0.1 - FUTURE DRIVERS OF CHANGE FOR THE ELECTRIC GRID	19
EXHIBIT 3.1.1 - DTEE GRID MODERNIZATION SCENARIOS.....	20
EXHIBIT 3.1.1.1 - LIGHT DUTY EV SALES AS A PERCENTAGE OF TOTAL VEHICLE SALES (2027 – 2037)	22
EXHIBIT 3.1.1.2 - COUNT OF EV LIGHT DUTY VEHICLES WITH EV PENETRATION (2027 – 2037)	23
EXHIBIT 3.1.1.3 - LIGHT DUTY ELECTRIC VEHICLE ENERGY CONSUMPTION (2027 – 2037)	23
EXHIBIT 3.1.1.4 - ELECTRIFICATION SCENARIO FORECASTS OF LOAD INCREASES (2027 - 2037)	24
EXHIBIT 3.1.1.5 - PERCENT OF CUSTOMERS SERVED BY OVER-FIRM SUBSTATIONS IN THE HIGH EV ADOPTION SCENARIO	25
EXHIBIT 3.1.2.1 - UPPER MIDWEST EXTREME WEATHER IS INCREASING IN FREQUENCY AND INTENSITY	27
EXHIBIT 3.1.2.2 - DETROIT METROPOLITAN AIRPORT WIND GUST DATA.....	28
EXHIBIT 3.1.2.3 – HIGHER CAPE DAYS HAVE BECOME MORE COMMON IN MICHIGAN.....	29
EXHIBIT 3.1.2.4 – THE NUMBER OF CUSTOMERS AFFECTED BY CAT STORMS IS INCREASING EACH YEAR	30
EXHIBIT 3.1.2.5 - TREE DAMAGE TO DTEE EQUIPMENT IN THE WEBBERVILLE COMMUNITY (JULY 26,2023)	31
EXHIBIT 3.1.3.1 - DG/DS SCENARIO CAPACITY FORECAST (2027 – 2037)	33
EXHIBIT 3.1.3.2 - PERCENTAGE OF CUSTOMERS ON SUBSTATIONS WHERE INSTALLED SOLAR CAPACITY EXCEEDS THE HOSTING CAPACITY LIMIT (2025 – 2037)	34
EXHIBIT 4.2.1.1 RELIABILITY STATISTICS - ALL WEATHER.....	39
EXHIBIT 4.2.2.1 5-YEAR AVERAGE CUSTOMER MINUTES OF INTERRUPTION BY CAUSE (SAIDI)	40
EXHIBIT 4.2.2.2 5-YEAR AVERAGE CUSTOMER INTERRUPTIONS BY CAUSE (SAIFI)	41
EXHIBIT 4.2.2.3 FIVE-YEAR AVERAGE OUTAGE EVENTS BY CAUSE.....	41
EXHIBIT 4.3.1.1 ASSET AGE SUMMARY	42
EXHIBIT 4.3.6.1 UNDERGROUND SYSTEM CABLE AGES AND LIFE EXPECTANCY	46
EXHIBIT 5.0.1: DTEE GRID MODERNIZATION STATUS	48
EXHIBIT 6.1.1 PROJECTED DTEE FIVE-YEAR DISTRIBUTION GRID PLAN INVESTMENTS	55
EXHIBIT 6.1.2-YEAR COST PER PILLAR WITH MOST SIGNIFICANT INVESTMENT FOR EACH.....	55
EXHIBIT 6.1.1.1 SYSTEM ALL WEATHER SAIDI	57
EXHIBIT 6.1.1.2 ALL WEATHER SAIFI	57
EXHIBIT 7.2.1.1 TREE-RELATED OUTAGE EVENT DIFFERENCE: ETTP VS. NON-ETTP CIRCUITS	59

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

EXHIBIT 7.2.2.1 TREE-RELATED CUSTOMER INTERRUPTION DIFFERENCE: ETPP VS. NON-ETTP CIRCUITS 59

EXHIBIT 7.2.3.1 TREE-RELATED CUSTOMER MINUTES INTERRUPTED DIFFERENCE: ETPP VS. NON-ETTP CIRCUITS 60

EXHIBIT 7.2.4.1 TREE-RELATED WIRE DOWN EVENTS DIFFERENCE: ETPP VS. NON-ETTP CIRCUITS 60

EXHIBIT 8.1.1 POLE TESTING 69

EXHIBIT 8.1.2 UTILITY POLE BENCHMARKING..... 69

EXHIBIT 8.1.3 POLE TOP EQUIPMENT SPECIFICATIONS..... 69

EXHIBIT 8.1.4 POLE AND POLE TOP PROGRAM FUTURE INVESTMENT..... 70

EXHIBIT 8.2.1.1 4.8kV CIRCUIT MILES HARDENED..... 72

EXHIBIT 8.2.1.2 4.8kV MILES OF ARC WIRE REMOVED 72

EXHIBIT 8.2.1.3 WIRE DOWNS BEFORE AND AFTER HARDENING..... 73

EXHIBIT 8.2.1.4 ALL-WEATHER SAIFI BEFORE AND AFTER HARDENING 74

EXHIBIT 8.2.1.5 SAIDI Ex-MEDS BEFORE AND AFTER HARDENING..... 74

EXHIBIT 8.2.2.1 4.8KV HARDENING ALTERNATIVES 75

EXHIBIT 8.2.3.1 FORECASTED CIRCUIT MILES HARDENED 76

EXHIBIT 8.2.3.2 FORECASTED MILES OF ARC WIRE REMOVED 77

EXHIBIT 8.3.3.1 SYSTEM EQUIPMENT REPLACEMENT PROGRAMS..... 81

EXHIBIT 8.5.1 PORTABLE SUBSTATION AND MOBILE GENERATOR 84

EXHIBIT 8.6.1 CE & CEMI PRE-STORM STRENGTHENING RELIABILITY IMPROVEMENTS 85

EXHIBIT 9.1.1.1 TOP 25 HIGHEST RANKED LOAD RELIEF SUBSTATIONS OVERVIEW..... 92

EXHIBIT 9.1.3.1 PROJECTED LOAD RELIEF CAPITAL INVESTMENT 96

EXHIBIT 9.2.1 – TRUNK LINE DIAGRAM EXAMPLE (RADIAL) 97

EXHIBIT 9.2.2 – TIE LINE DIAGRAM EXAMPLE (NETWORK) 97

EXHIBIT 9.2.3 DTEE SUBTRANSMISSION CIRCUITS 98

EXHIBIT 9.2.3.1 CRITERIA TO PRIORITIZE SUBTRANSMISSION REDESIGN AND REBUILD PROJECTS 100

EXHIBIT 9.2.3.2 HIGHEST RANKED 25 SUBTRANSMISSION LOAD RELIEF PROJECT DIMENSIONS OVERVIEW 102

EXHIBIT 9.2.4.1 PROJECTED SUBTRANSMISSION REDESIGN AND REBUILD CAPITAL INVESTMENT 105

EXHIBIT 9.3.1.1 GENERAL PURPOSE SUBSTATIONS BY LOW SIDE kV..... 108

EXHIBIT 9.3.1.2 DTEE DISTRIBUTION CIRCUITS – LINE MILES BY LINE VOLTAGE..... 108

EXHIBIT 9.3.1.3 DTEE DISTRIBUTION VOLTAGE MAP 110

EXHIBIT 9.3.3.1 DOWNTOWN CITY OF DETROIT INFRASTRUCTURE (CODI) SCOPE AREA 113

EXHIBIT 9.3.3.2 CODI PROGRAM SUBSTATION AREAS..... 114

EXHIBIT 9.3.3.3 4.8kV CONVERSION MAP 116

EXHIBIT 9.3.3.4 – ISO DOWN CIRCUIT 117

EXHIBIT 9.3.3.5 NUMBER OF CIRCUITS WITH ISO DOWNS AND MILES OF 4.8kV 117

EXHIBIT 9.3.5.1 PROJECTED 4.8kV CONVERSION CAPITAL INVESTMENT 119

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

EXHIBIT 9.3.6.1 – GPM DIMENSIONS RELATED TO DISTRIBUTION SYSTEM LOAD RELIEF 120

EXHIBIT 9.3.6.2 – CONVERSION PROJECTS TO ADDRESS 25 4.8kV SUBSTATIONS WITH HIGHEST LOADING
CONSTRAINTS 121

EXHIBIT 9.3.7.1 PONTIAC 8.3 kV CONVERSION CAPITAL INVESTMENT..... 123

EXHIBIT 10.0.1: MODERN DISTRIBUTION OVERVIEW..... 129

EXHIBIT 10.1.1: AUTOMATION PROGRAM – RETROFIT CIRCUIT EXAMPLE 134

EXHIBIT 10.1.2: KEY INVESTMENT HIGHLIGHTS FOR GRID AUTOMATION..... 135

EXHIBIT 10.1.3: KEY INVESTMENT AND TIMELINE FOR GRID AUTOMATION 136

EXHIBIT 10.1.4: PERCENT OF RECLOSERS INSTALLED ON DTEE’S SYSTEM 137

EXHIBIT 10.1.5.2: DTEE FUTURE NETWORK TECHNOLOGY LANDSCAPE 140

EXHIBIT 10.1.5.1: DTEE CURRENT NETWORK TECHNOLOGY LANDSCAPE 140

EXHIBIT 10.1.1.3: NWA MATURITY AND FUNCTIONALITY 142

EXHIBIT 10.2.1.1: DER OPTIONS COMMERCIALY AVAILABLE TO CUSTOMERS..... 145

EXHIBIT 10.2.1.2: KEY INVESTMENT HIGHLIGHTS FOR GRID MANAGEMENT 146

EXHIBIT 10.2.1.3: KEY INVESTMENT AND TIMELINE FOR GRID MANAGEMENT..... 147

EXHIBIT 10.2.2.1: GENERAL CONFIGURATION OF THE ADVANCED DISTRIBUTION PLANNING SYSTEM 150

EXHIBIT 10.2.2.2: KEY INVESTMENT HIGHLIGHTS FOR DISTRIBUTION PLANNING 152

EXHIBIT 10.2.2.3: KEY INVESTMENT AND TIMELINE FOR DISTRIBUTION PLANNING..... 154

EXHIBIT 10.2.3.1: KEY INVESTMENT HIGHLIGHTS FOR WORK MANAGEMENT AND SCHEDULING 155

EXHIBIT 10.2.3.2: KEY INVESTMENT AND TIMELINE FOR WORK MANAGEMENT AND SCHEDULING..... 156

EXHIBIT 10.2.4.1: KEY INVESTMENT HIGHLIGHTS FOR ASSET MANAGEMENT 157

EXHIBIT 10.2.4.2: KEY INVESTMENT AND TIMELINE FOR ASSET MANAGEMENT..... 158

EXHIBIT 10.2.5.1: KEY INVESTMENT HIGHLIGHTS FOR MOBILE TECHNOLOGY 159

EXHIBIT 10.2.5.2: KEY INVESTMENT AND TIMELINE FOR MOBILE TECHNOLOGY..... 160

EXHIBIT 11.0.1 PROJECTED DISTRIBUTION GRID PLAN INVESTMENTS 161

EXHIBIT 11.0.2 PROJECTED DISTRIBUTION GRID PLAN INVESTMENTS (SORTED BY REFERENCE SECTION NUMBER)
..... 161

EXHIBIT 12.1.1 GLOBAL PRIORITIZATION MODEL IMPACT DIMENSION 165

EXHIBIT 12.2.1.2 2022 ALL WEATHER SAIDI FOR VULNERABLE CENSUS TRACTS WITH MIEJ SCORE OF 80% TO
100% 169EXHIBIT 12.2.1.1 2022 ALL WEATHER SAIDI BY CENSUS TRACT FOR DTE ELECTRIC (FULL ELECTRIC SERVICE
AREA) 169EXHIBIT 12.2.1.4 2022 ALL WEATHER SAIDI FOR VULNERABLE CENSUS TRACTS WITH MIEJ SCORE OF 80% TO
100% (METRO DETROIT AREA)..... 170EXHIBIT 12.2.1.3 2022 ALL WEATHER SAIDI BY CENSUS TRACT FOR DTE ELECTRIC (METRO DETROIT AREA)
..... 170

Michigan Public Service Commission

DTE Electric Company

2023 Distribution Grid Plan U-20147

EXHIBIT 12.2.1.5 RELIABILITY PERFORMANCE OF VULNERABLE CENSUS TRACTS (MIEJ SCORE OF 80% TO 100%)

VERSUS SYSTEM AVERAGE	171
EXHIBIT 12.2.1.6 INVESTMENTS IN VULNERABLE COMMUNITIES (CENSUS TRACTS WITH MIEJ SCORE OF 80% TO 100%)	172
EXHIBIT 12.2.3.1 INVESTMENT OF CIRCUITS IN EJ COMMUNITIES THAT FALLS IN THE 4 TH RELIABILITY QUARTILE	174
EXHIBIT 14.1.1 MUTUAL ASSISTANCE GROUPS WITHIN THE UNITED STATES	184
EXHIBIT 15.1.3.1 EMERGENT REPLACEMENTS INVESTMENT (\$ MILLIONS)	191
EXHIBIT 15.2.1 CONNECTIONS, RELOCATIONS AND OTHER INVESTMENT (\$ MILLIONS).....	192
EXHIBIT 17.1.1 ELECTRIC RELIABILITY IMPROVEMENT MAP (DTE SERVICE TERRITORY)	200
EXHIBIT 17.1.2 ELECTRIC RELIABILITY IMPROVEMENT MAP (METRO DETROIT)	200
EXHIBIT A.1 DTEE DISTRIBUTION SYSTEM	205
EXHIBIT A.2 RELIABILITY INDICES DEFINITIONS	205
EXHIBIT A.3 RELIABILITY STATISTICS - EXCLUDING MEDS	206
EXHIBIT A.4 RELIABILITY STATISTICS - CATASTROPHIC STORMS (DTEE DEFINITION)	207
EXHIBIT A.5 RELIABILITY STATISTICS – NON-CATASTROPHIC STORMS (DTEE DEFINITION)	207
EXHIBIT A.6 RELIABILITY STATISTICS - EXCLUDING ALL STORMS	207
EXHIBIT A.7 UNDERGROUND SYSTEM CABLE TYPES	208
EXHIBIT B.1.1 SUBSTATION IN NORMAL AND CONTINGENCY STATES	208
EXHIBIT B.1.2 TOP 25 HIGHEST RANKED LOAD RELIEF SUBSTATIONS – PROJECT SUMMARY	209
EXHIBIT B.1.3 ADDITIONAL LOAD RELIEF PROJECTS	213
EXHIBIT B.1.4 PROJECTED COSTS AND TIMELINE FOR LOAD RELIEF PROJECTS	216
EXHIBIT B.2.1 SUBTRANSMISSION PROJECTS SUMMARY	217
EXHIBIT B.2.2 PROJECTED INVESTMENT AND TIMELINE FOR SUBTRANSMISSION PROJECTS	225
EXHIBIT B.3.1 4.8 kV CONVERSION PROJECTS	228
EXHIBIT B.3.2 PROJECTED COSTS AND TIMELINE FOR 4.8 kV CONVERSION PROJECTS	235
EXHIBIT D.1 KEY THEMES FROM CUSTOMER FEEDBACK (FEBRUARY 2023 ICE STORM)	252
EXHIBIT E.1.1 DTEE FIBER LOOP (DETROIT)	254
EXHIBIT E.3.1 SOLUTION OPTIONS	256
EXHIBIT E.3.1.1 CAPITAL WORK PLAN 16.5.2 TARGETED STUDY FINDINGS	257

Glossary

ADMS	Advanced Distribution Management System
ALA	Area Load Analysis
AMI	Advanced Metering Infrastructure
APTS	Automatic Pole Top Switch
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
Capacity	Amount of electrical demand that a single piece or group of electrical equipment can deliver based on safety and preservation of the asset
CELIDt	Customers Experiencing Long Interruption Durations of t hours or more
CEMIn	Customers Experiencing Multiple Interruptions of n or more
CHP	Combined Heat and Power
CODI	City of Detroit Infrastructure (Downtown)
Customer 360	DTEE's customer information and billing system
DDO	Distribution Design Orders
DDS	Distribution Design Standards
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management Systems
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DO	Distribution Operations Organization of DTE Electric Company
DOE	Department of Energy
DS	Distributed Storage

DTEE	DTE Electric Company
EEI	Edison Electric Institute
E-ISAC	Electricity Information Sharing and Analysis Center
EMS	Emergency Management System
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
ESOC	Electric System Operations Center
ETTP	Enhanced Tree Trimming Program
FLISR	Fault Location, Isolation and Service Restoration
Gas Breaker	Circuit breaker where the interrupting arc quenching is done with compressed gas
Gas Cable	Underground cable which requires pressurized gas to maintain the insulation integrity
GIS	Geographical Information System
ICS	Incident Command System
IEEE	Institute of Electrical and Electronics Engineers
ISO	Isolation transformer
Industrial Control System	A general term that encompasses several types of control systems and associated instrumentation used in industrial production technology, including supervisory control and data acquisition (njnhg) systems, distribution management systems (DMS), and other smaller control system configurations often found in the industrial sectors and critical infrastructure
IRP	Integrated Resource Planning
Line losses	Electrical power loss resulting from an electric current passing through a resistive element (e.g., conductor)

Jumping Point	A location on a distribution circuit in proximity to a second distribution circuit where the two can be electrically tied together
Line Sensors	Devices installed on distribution circuits that provide load and fault data
Manhole	An underground structure for cable pulling and splicing
MED	Major Event Day - defined in IEEE Standard 1366 as any day in which the fdaily SAIDI exceeds a threshold value
MPSC	Michigan Public Service Commission
NDAS	Network Database and Applications Support
NEETRAC	National Electric Energy Testing, Research and Applications Center
NERC	North American Electric Reliability Corporation
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NESC	National Electric Safety Code
Netbank	Distribution network design used in heavy-load-density city areas which provides high reliability
Oil Breaker	Circuit breaker where the interrupting arc quenching is done in oil
O&M	Operation and Maintenance
OMS	Outage Management System
Overload	Electrical demand that exceeds the electrical capacity to serve
PCB	Polychlorinated biphenyl - now considered an environmental contaminant
PERT	Power Equipment and Relay Testing
PI	Data collection software
PILC	Paper in Lead Cable - refers to the type of insulation/jacket on an underground cable
PM	Preventative maintenance - routine scheduled maintenance based on time or number of operations

PON	Power Outage Notification
Primary	Any part of the electrical system energized at 4.8 kV, 8.3 kV, or 13.2 kV
PSSE	Data modeling software
PTMM	Pole Top Maintenance and Modernization
PTS	Pole Top Switch
RBR	Restore Before Repair. It is the practice that customers (load) are transferred to adjacent circuits or substations to restore power before repair can be completed on the failed section of the circuit
Recloser	Sectionalizing device which opens upon detection of fault current
Redundancy	Ability to continue to serve in the event of a contingency condition
Relay	Electrical switch used to initiate operations of other electrical equipment
ReliabilityFirst	One of the eight regional entities that are responsible for ensuring the reliability of the North American bulk power system under Federal Energy Regulatory Commission approved delegation agreements with the North American Electric Reliability Corporation, pursuant to the Energy Policy Act of 2005. DTEE's service territory is in ReliabilityFirst region
RM	Reactive maintenance resulting from a mis operation or malfunction
ROW	Right-of-Way
RTU	Remote Terminal Unit that sends or receives telemetry data to or from a master control
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
Secondary	Any part of the electrical system energized at 120/240 volts
Service	The conductor / cable and equipment that connects a customer to the electrical system

SFI	Smart Fault Indicators
STDF	Subtransmission Distribution Facility
Stranded load	Under contingency conditions, electrical demand that cannot be readily served through available jumpering or mobile generation
Subtransmission	Any part of the electrical system energized at 24 kV, 40 kV, 120 kV, or higher
Substation	A facility of the electrical power grid that allows for the connection and/or switching of circuits and/or the transformation of voltage from one level to another
TARA	Data modeling software
Through Fault	A fault occurring on the secondary side of a power transformer which may damage the insulation of the transformer
TIE (Tie line)	A subtransmission circuit that interconnects two or more substations with power flow normally from any of the substations
TRK (Trunk line)	A radial subtransmission circuit with power flow normally in one direction to serve substation or individual customer loads at 24 kV or 40 kV
TR-XLPE cable	Tree retardant cross-linked polyethylene - refers to the type of insulation on an underground cable
URD	Underground Residential Distribution
Vacuum Breaker	Circuit breaker where the interrupting arc quenching is done in a vacuum
Vault	An underground structure for cable pulling and splicing that also contains power equipment such as transformers and switches
VCL Cable	Varnished Cambric Lead - refers to the type of insulation/jacket on an underground cable
XLPE cable	Cross-linked polyethylene - refers to the type of insulation on an underground cable